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ANALYSIS OF THE ENERGY RESOURCES AND DEMAND OF WESTERN EUROPE

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ANALYSIS OF THE ENERGY RESOURCES AND DEMAND OF WESTERN EUROPE

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This report examines the future demand for energy of Western Europe through the year 1985. Particular attention is given to the impact of the tripling of the price of oil on total energy demand, demand for oil, and the development of competitive sources of energy in terms of increased domestic resources and alternate sources of supply to the Organization of Petroleum Exporting Countries (OPEC).

The forecast energy demand by consuming sector and the projected supplies by

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fuel of the EEC(9) have been developed. The results indicate that total energy demand in 1975, 1980, and 1985 represents increases of 11 percent, 27 percent, and 64 percent, respectively, over 1972 consumption. There is a marked decline in the growth rate of energy consumption through 1980 in response to the higher fuel prices accompanying the oil embargo of 1973. It appears that Western Europe will continue to be heavily dependent on OPEC oil and very vulnerable (as is the U. S.) to another embargo. The successful development of North Sea resources and increased imports from the Soviet Union and Bloc countries can only lessen this dependence slightly, but may play a substantial role in stablizing prices. The development of the North Sea has been hindered by rapidly rising costs and taxation policies. Another significant event in the resource area is that the decline in coal production has been halted.

The long-term impact of the oil price rise for Europe as a whole is not expected to be serious if capital and monetary markets work properly. Because supply, demand, and price cannot adjust immediately to large changes, some short-term economic dislocations can be expected. What the OPEC countries will do, or could do, with their money is a major concern, though. The potential for severe economic disruption exists if the OPEC countries switch petrodollar deposits in and out of different currencies.

Various geopolitical scenarios which could arise from the European energy situation are discussed. The potential for technology transfer from the U. S. is briefly examined.

ANALYSIS OF THE ENERGY RESOURCES AND DEMAND OF WESTERN EUROPE

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Section 1

INTRODUCTION

A current and growing dependence on foreign sources of energy is a condition which is shared by most of the industrialized world. Of the major industrial nations, only the Soviet Union is a net exporter of energy. Western Europe, taken as a whole, consumes approximately half of the energy consumed by the U. S. ; half of its energy must be imported (compared to 20 percent for the U. S. and 70 percent for Japan). The per capita energy consumption is roughly one-third of the United States' and 50 percent greater than Japan's. At the present time, Western Europe is almost self-sufficient in coal and gas production but produces domestically less than 5 percent of the petroleum it consumes.

Western Europe's economy is no longer based on coal but is one in which oil and gas compete on a near even basis in some areas, while in most other areas oil and gas have overtaken coal. In coal-producing countries of Western Europe the use of coal as an energy source has remained economically viable only through subsidies and higher taxes on oil. The situation is complicated by the fact that, although it is convenient to speak of "Western Europe" as a single entity, it is a collection of independent sovereign states each with its own national interests.

This report examines the future demand for energy of Western Europe through the year 1985. Particular attention is given to the

impact of the tripling of the price of oil on total energy demand, demand for oil, and the development of competitive sources of energy in terms of increased domestic resources and alternate sources of supply to the Organization of Petroleum Exporting Countries (OPEC).

Section 2 of this report examines the resource scenario. The promise of North Sea oil and gas is examined in light of the current problems of cost of exploration and development, and governments' taxation policies. Section 3 presents the methodology followed in developing demand projections which reflect European energy useage patterns and current fuel prices. The methodology is followed by the demand projections through 1985, showing the split by fuel and consuming sector for the region and its largest countries. Section 4 discusses the impact of the projected energy situation on resource development, the economy of the region, and the potential for alleviating the situation through technology transfer. Appendix A provides greater detail on domestic resources of Western Europe. Appendix B provides greater detail on electric power forecasts — particularly the rate of introduction of nuclear power. Appendix C provides more detailed energy balances for the region and its largest countries.

1.1 TERMS OF REFERENCE

There are a number of terms and conversion factors used throughout the report which should be defined at the beginning to avoid confusion. The first item concerns the definition of the countries included in the study. The broadest category includes the European members of the Organization for Economic Cooperation and Development — OECD Europe. All of Western Europe is represented, including the Scandinavian countries, Greece, Turkey, and Ireland.

Another broad category is the nine countries of the European Economic Community, often termed the Common Market. The EEC(9) includes Germany, the United Kingdom, France, Italy, the Netherlands, Belgium, Denmark, Ireland, and Luxembourg. In the study, it was convenient to combine data for the U. K. and Ireland, and for Belgium and Luxembourg.

The question of the appropriate units with which to express energy demand was answered by expressing the principal results in terms of both kilocalories and BTUs. The kilocalorie is the standard unit of measure in Europe. The BTU, or more precisely the Quad (for 10^{15} or quadrillion BTUs), is the unit of favor in the U. S. The nature of the source data favored the use of kilocalories as the basic unit of measure, however. An alternative form of the kilocalorie is a unit of 10^{13} kilocalories which approximates the equivalent energy content of one million metric tons of oil equivalent (MTOE). Similarly, the unit of one million metric tons of coal equivalent is sometimes used. Summarizing:

$$10^{13} \text{ Kcal} = 1 \text{ MTOE} = 1.43 \text{ MTCE}$$

$$\begin{aligned} 1 \text{ Quad} &= 10^{15} \text{ BTU} \approx 25 \text{ MTOE} \\ &= 10^{9} \text{ ft}^{3} \text{ (gas)} = 42 \cdot 10^{6} \text{ tons (coal)} \\ &= 1/2 \cdot 10^{6} \text{ BPD (oil)} \end{aligned}$$

$$\text{or} \quad 1 \text{ Quad/Year} = 1/2 \text{ Million Barrels Per Day (oil)}$$

1.2 PERSPECTIVE

An appreciation of the importance of Western Europe as a consumer of energy and as a region dependent on energy imports can be gained by an examination of Figure 1.1. The figure shows energy demand projections for Japan, Europe and the U. S. which were prepared prior to the 1973 oil embargo and the associated sharp increase

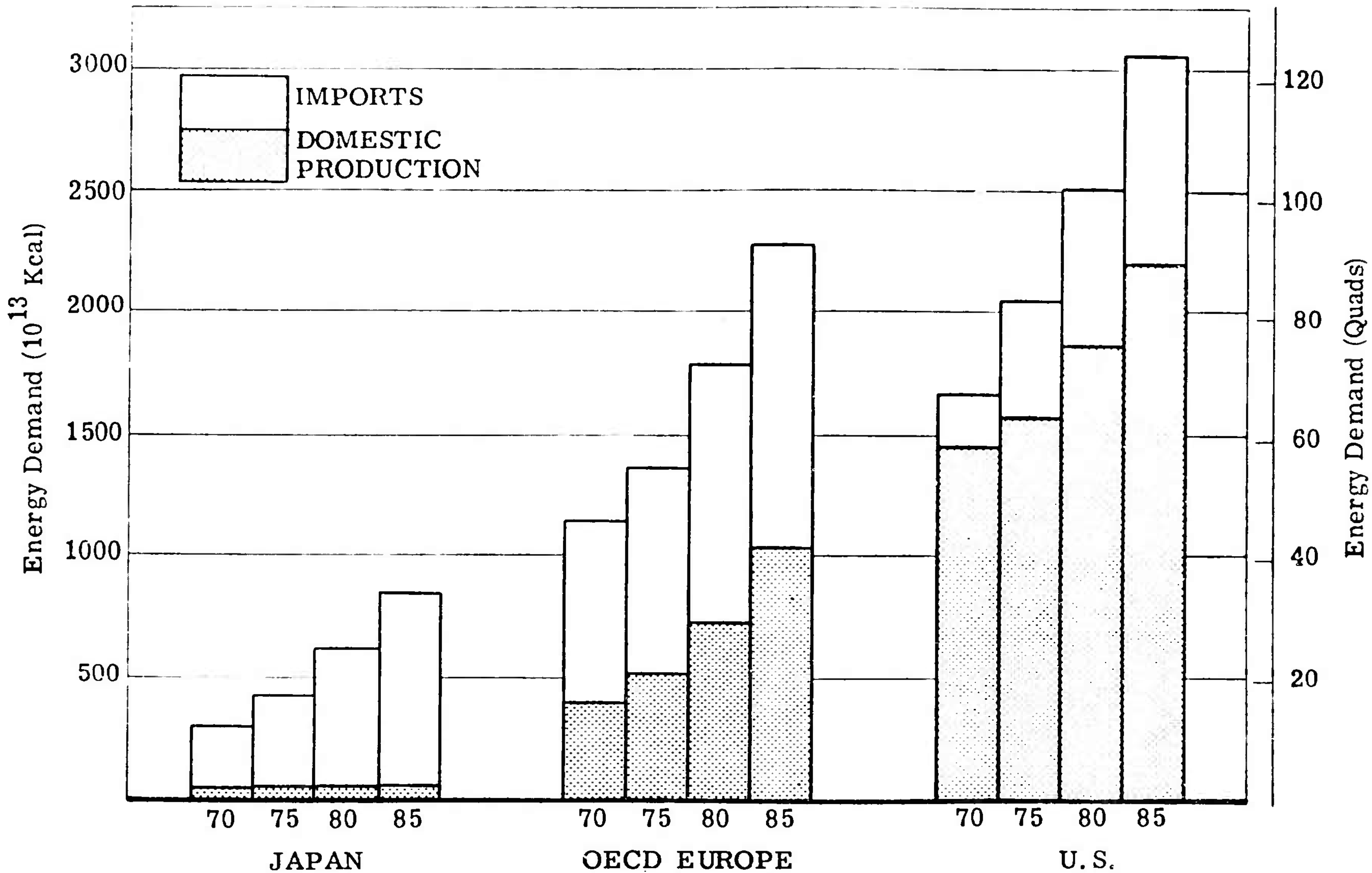

Figure 1.1. Energy Demand Growth and Imports Comparisons (Projections Prior to 1973 Oil Embargo)

in the price of oil. The Japan projections were prepared by SAI in a previous study for ARPA.[1] The U.S. projections are those of the National Petroleum Council for intermediate demand growth and Supply Case III.[2] The European projections are those of the community itself from sources described in Section 1.4. From Figure 1.1 one can see that on an absolute basis Western Europe has the largest import demand. However, on a percentage basis, Europe falls in the middle — a requirement greater than that of the U.S. but less than the almost complete dependence of Japan.

1.3 STUDY APPROACH

The approach employed in conducting this study of Europe's future energy demand closely parallels that employed in studying Japan's energy situation. The study began by developing a detailed energy balance for the baseline year. This procedure uncovers most of the problems contained in units of measure, methods of accounting, treatment of stockpiles, double counting, coal to producer gas conversion, and the input energy equivalent of generated electric power. The proper accounting of electric power is both difficult and important — important because it accounts for a sizeable fraction of total energy consumption and difficult because production is expressed in kilowatt hours which have to be converted to input energy considering both conversion efficiency and input fuel energy content. The next step is to examine the domestic supply situation for the region. Current reserve estimates, exploration activities, current rates of production, and future production estimates are important considerations. Potential sources of delay in meeting production milestones and political, economic or technological constraints on availability of needed imports have to be identified.

Estimates of future energy demand begin with projections prepared by the countries themselves which are evaluated first to ensure internal self-consistency and agreement with reasonable estimates of GNP and population growth, and energy usage by consuming sector. These initial projections are then modified to reflect the economic behavior and availability of the regional energy resources. Based on a set of demand growth projections and associated impact requirements the potential economic and geopolitical consequences are then assessed. Finally, the potential of technology transfer from the U.S. which might alleviate identifiable problems by increasing domestic supply are identified.

1.4 SOURCES

It is important to summarize the sources of information which provided the data base for the study so that the reasonableness of the conclusions can be evaluated. Primary data on historical energy consumption and demand projections came from the OECD and EEC(9) and included:

- Statistics of Energy 1958-1972[3]
- Prospects of Energy Demand in the Community 1975-1980-1985[4]
- Expenditure Trends in OECD Countries 1960-1980[5]
- OECD Economic Outlook #14[6]
- Long-Term Energy Assessment[7].

Conclusions on the response of the various countries' economies to changes in the price of fuels were based in part on: Energy Through the Year 2000[8]; Project Independence Blueprint[9]; and the

recent work of Hudsen and Jorgenson[10]. ·mation on indigenous energy resources and exploration was obtained from a large number of sources which included the International Petroleum Encyclopedia[11], Oil and Gas Journal, the Bureau of Mines, and publications of OECD, EEC, and the U. N.

1.5 SUMMARY OF RESULTS

The forecast energy demand by consuming sector and the projected supplies by fuel of the EEC(9) are summarized in Table 1.1. The table shows that total energy demand in 1975, 1980 and 1985 represents increases of 11 percent, 27 percent, and 64 percent, respectively, over 1972 consumption. There is a marked decline in the growth rate of energy consumption through 1980 in response to the higher fuel prices accompanying the oil embargo of 1973.

Several important results of the study are summarized briefly below.

1.5.1 Resources

Despite many moves taken to diversify supply in response to the dramatic increase in oil price, Western Europe will continue to be heavily dependent on OPEC oil and very vulnerable (as is the U.S.) to another embargo. The successful development of North Sea resources and increased imports from the Soviet Union and Bloc countries can only lessen this dependence slightly, but may play a substantial role in stabilizing prices. However, the development of the North Sea has been hindered by rapidly rising costs and taxation policies. At a minimum the potential contribution of the North Sea for alleviating European import requirements has been delayed several

Table 1.1. EEC(9) Energy Supply and Demand Projections Through 1985
(10^3 Kilocalories)

		1972	1975	1980	1985
SUPPLY	COAL	224.5	220.7	207.2	220.7
	OIL	588.6	637.4	660.4	833.3
	GAS	112.0	164.0	248.6	320.0
	HYDRO & NUCLEAR	42.7	49.4	114.9	210.7
	TOTALS	967.8	1071.5	1231.1	1584.7
DEMAND	COMMERCIAL-RESIDENTIAL	321.1	349.4	334.2	428.0
	INDUSTRY	425.4	471.7	633.2	812.9
	TRANSPORTATION	129.3	146.8	146.9	192.3
	NON-ENERGY	51.6	61.2	79.4	110.1
	BUNKERS	40.4	42.4	37.4	41.4
	(ELECTRICITY)*	245.4	275.9	373.9	527.3

*Not Included in Totals

years. Another significant event in the resource area is the decline in coal production has been halted. This in itself is a notable achievement as investment costs and labor shortages act against the coal production, despite substantial reserves.

1.5.2 Economic Impact

As bad as current economic conditions are worldwide, the long-term impact of the oil price rise for Europe as a whole is not expected to be serious if capital and monetary markets work properly. Because supply, demand, and price cannot adjust immediately to large changes, some short-term economic dislocations can be expected. The situation could be exacerbated if fuel shortages or tight money lead to harsh restrictive measures such as rationing or tariffs. Particular geographic regions (poor areas with large energy bills) or certain sectors of a country's economy (energy intensive industries) may be in for real trouble. Some towns could go bankrupt, for example.

What the OPEC countries will do, or could do, with their money is a major concern. Acting in their own best interests, they should probably invest in a broad spectrum of industries and financial institutions worldwide — akin to buying a world mutual fund where their visibility is low and risk of nationalization is reduced. On the other hand, the potential for severe economic disruption exists if the OPEC countries switch petrodollar deposits in and out of different currencies.

An additional consideration is that OPEC retains the option to reduce oil prices again. This curtails capital investment in energy resource development since the various processes under development (coal gasification, coal liquefaction, etc.) will produce fuels whose

equivalent cost will be \$7-\$12 bbl or higher. This means that government incentives, guarantees and or subsidies will be required if some measure of energy independence is to be achieved.

1.5.3 Geopolitical Implications

A positive development of the Western European energy situation has been the more effective economic and industrial integration of the member countries through trade agreements, pipeline construction, and joint exploration and development projects (particularly in the North Sea). Some potential for strife in the North Sea area exists because of Norway's "go-slow" development plans which are resented by her energy-hungry neighbors. Further in the future, problems may arise between the two countries of the community (Germany and the Netherlands) which have been exporting fuel as those exports cease because of local demand — especially if these countries are prospering while the others are experiencing hard times. An additional possibility, not explored during the study, is the development of stronger ties between East and West Germany (at the expense of the Warsaw Pact countries and NATO).

The alternative to OPEC oil and gas that may be offered by the Soviet Union and Bloc countries has far reaching implications. It gives the Soviet Union leverage for participating in the discussions attempting to settle the Arab-Israeli dispute as well as considerable trade credits with the West. An increasing dependence by Western Europe on Soviet resources could be manipulated to pit one country against the other to obtain favorable long-term commitments. On the other hand, the potential of the energy situation serving as a vehicle for improved East-West relations should not be overlooked.

1.5.4 Technology Transfer

There is little short-term potential for alleviating Western Europe's energy situation through technology transfer from the U.S. Secondary and tertiary oil recovery schemes were developed in the U.S.; however, this technology is currently available worldwide through the multinational oil countries. Although U.S. coal mining technology is foremost in the world and new research programs to increase automation are being sponsored by the Department of the Interior, since the European mines have been subsidized for years it will take a major effort to maintain the current work force and current production levels. Longer term prospects for technology transfer depend on the success of the U.S. research programs — the best funded in the world. An eager market can be counted on for economically viable coal gasification and liquefaction processes or fusion power.

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Section 2

DOMESTIC ENERGY RESOURCES OF WESTERN EUROPE

2.1 HISTORICAL BACKGROUND

Western Europe has historically based its industry close to energy sources, with the first industrial centers located at sites where falling water powered the mills. In Switzerland and Norway significant energy still comes from falling water which generates hydroelectric power. Western Europe's abundant supply of coal has been heating its forges for several thousand years. With the invention of the steam engine, their ample domestic supplies of coal provided new power for the textile mills of England and the manufacturing plants of Germany, and shortly thereafter powered the growing rail transportation system of Europe.

2.1.1 Coal to Oil

Coal was a satisfactory and inexpensive fuel, but it had several drawbacks. It was difficult to mine and awkward to transport. As a result, industrial centers were located close to coal deposits or along rivers and rail lines suitable for transporting coal. Until World War II, indigenous oil was scarce and the bulk of petroleum products had to be imported, so coal was used to fuel industry and provide electricity; it could not be used to propel automobiles — and so oil was used but was confined primarily to the transportation sector. After World War II, however, the availability

of inexpensive middle-eastern oil completely changed the energy picture. Oil was not only available in quantity, it was inexpensive, caused less pollution, was more flexible in its uses and applications, and was easier to transport. Pipelines supplemented rail. Most new power plants, and many new industrial plants were designed to use oil. Consequently, and possibly without fully realizing the geopolitical consequences, Western Europe exchanged reliance on an accessible and secure domestic fuel for dependence upon an imported fuel.

As long as the multi-national oil companies controlled the complete system from exploration through development, transportation, refining and distributing, there was no supply problem. Oil supplying nations, however, began to exert political power.

2.1.2 Emergence of the Netherlands: Role of Natural Gas

Europe began to develop an energy economy based heavily on oil. Giant refinery complexes were built in the major port areas, particularly the Europort area of Rotterdam, but also at Le Harve, Marseilles, Genoa, Southampton, and others. Of these, however, the Rotterdam complex was the most significant, and propelled the Netherlands to the forefront of the inter-European energy system. An extensive network of pipelines was constructed across Europe, a large percentage originating in the Rotterdam Europort complex and other major port cities. A major manifestation of the Common Market was a common oil import and transportation infrastructure, in which traditional frontiers had minimal significance.

The role of the Netherlands moved from significant to vital in the European energy picture with the discovery of the Gronigen gas field on the North coast in 1969. The field, one of the world's

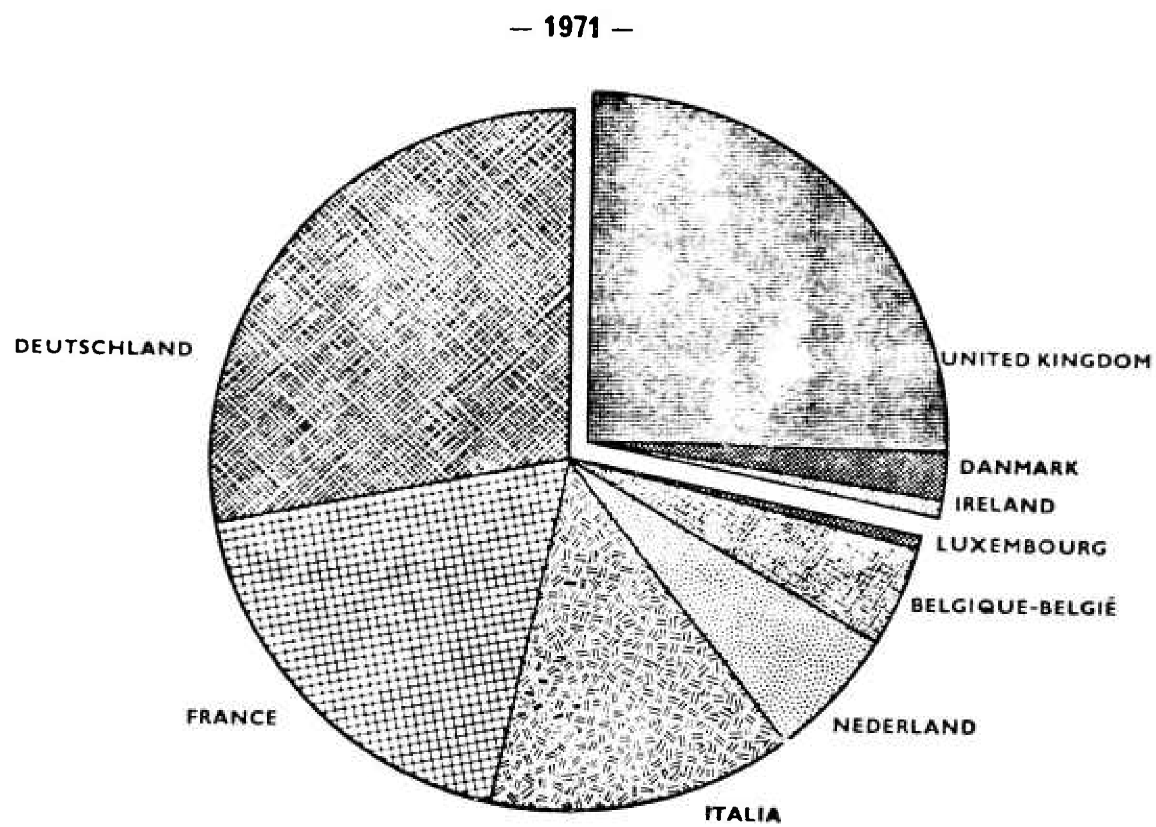
largest, spawned a network of gas pipelines, primarily to Germany and the industrial areas of Belgium, but also into France and as far south as Italy. Energy supply industry patterns changed, as gas moved to the forefront. Industrial plants, whose conversion to oil might have been marginal or too expensive, had a second opportunity to change to plentiful and inexpensive domestic natural gas. New plants were constructed to use this fuel, and gas began to displace, not oil (which had previously displaced coal), but still more coal, particularly that used in municipal "town gas" production. The impact on the already declining European coal industry was severe, as will be discussed subsequently.

2.1.3 Decline of Great Britain: Pre-North Sea

Great Britain was essentially isolated from these developments. No pipelines connected Gronigen with the U.K. Large terminal facilities such as Milford Haven in Wales, and Bantry Bay in Ireland, were established to handle supertankers from the Middle East. Small natural gas shows on the North Sea coast indicated that the U.K. might make a small-scale conversion from coal to oil and gas — but energy and industrial development in the U.K. became less integrated with the continent, despite belated U.K. entry into the Common Market. The U.K. began to develop her own energy policies and resources.

2.1.4 Pre-North Sea Energy Distribution Patterns

Western Europe's demand for energy of all types is shown in Figure 2.1. The figure was prepared using 1971 data, after Gronigen and North Sea discoveries, but before they were making a significant impact on the overall energy supply. Crude oil accounted for



Source: Statistical Office of the European Communities, Luxembourg[12]

Figure 2.1. Pre-Embargo European Energy Distribution

approximately 50 percent of the supply, bituminous and lignite coal slightly more than 25 percent, and the remainder was divided among natural gas, including some Gronigen, hydroelectric, and a small quantity of nuclear power.[12]

2.2 SUMMARY OF WESTERN EUROPE RESERVES

Appendix A discusses the major energy reserves of Western Europe, namely the oil and gas of the North Sea, and the still-substantial continent-wide coal reserves. The following paragraphs summarize the significance of these reserves.

2.2.1 North Sea

Development of the North Sea occurred after geologic correlation was found between the formations containing the Gronigen gas field of the Netherlands and small natural gas finds on the south central coast of England (see Figure 2.2). Based on findings and development wells drilled between 1970 and 1974, the following can be stated with confidence:

- North Sea Oil
  - North Sea oil reserves could sustain the EEC(9) for 8 years, based on 1972 rates of oil consumption and assuming no slackening of demand either by mandated energy conservation programs or by high prices. The reserves may be compared to approximately three North Slopes of Alaska, accepting the current estimates of 9.6 billion bbl; approximately two-third the remaining economically-recoverable reserves of the U.S., namely the lower-48-states plus Alaska; and approximately one-third the reserves of Saudi Arabia.[11]

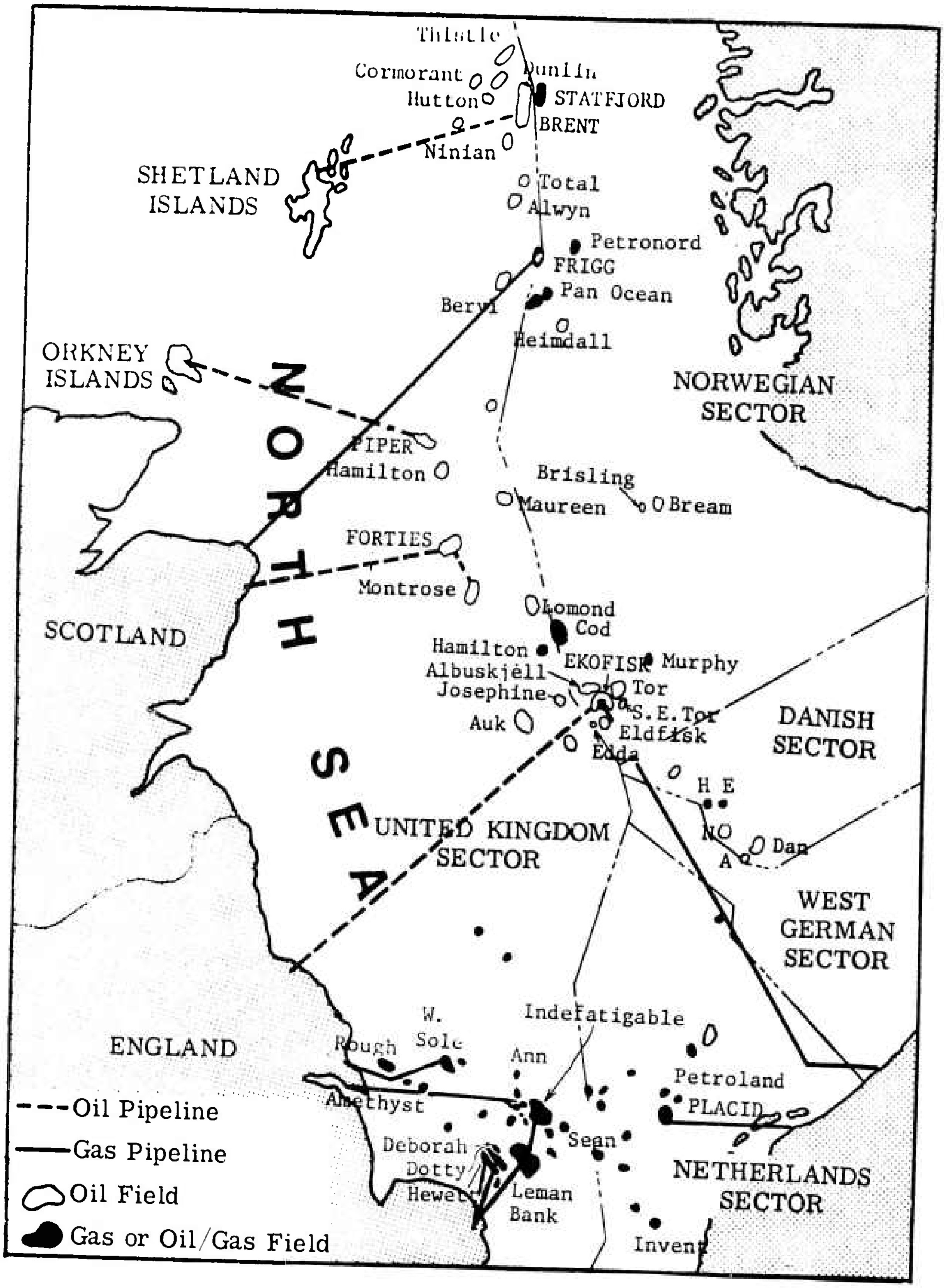


Figure 2.2. Known Resources in the North Sea

- North Sea Gas

  - North Sea gas reserves could sustain the EEC(9) for 50 years, based on 1972 gas consumption. If the gas is converted to crude oil equivalents, North Sea gas reserves equal 20 years of EEC(9) oil consumption. They are the equivalent of twice the known U. S. gas reserves and are slightly less than twice the gas reserves of Iran.[11]

Estimates of reserves for the North Sea vary widely. Extraction of North Sea oil and gas is proving to be expensive and some of the "marginal" fields may only be worked if oil and gas prices are very high, or through extensive government inducements. Working the deep fields (from 400 to 600 feet of water) in the vicinity of the 62d parallel and north involves massive expenses. Each new discovery escalates the reserve estimates which range from 42 billion bbls on the conservative side to nearly three times that number on the speculative side. Estimates examined from innumerable sources, by the authors over the past year, not only fluctuate widely but seem to ignore, in many instances, the economic facts of life in establishing the very expensive development and transportation systems needed to bring North Sea oil and gas ashore to refineries. Thus even the conservative estimate of 42 billion bbls of oil is higher than the most current estimate of 28.4 billion bbls which is "economically recoverable." Estimates of 138 billion bbls which may be "ultimately recoverable reserves" must be subject to the same skepticism. The economics of development, given the current state of the worldwide economy and inflationary trends, cannot be forecast with the accuracy with which the geologist can estimate the reserves, based on geophysical, exploration, and drilling data. Gas reserves are subject to similar fluctuation. Appendix A has attempted to follow consensus figures

wherever possible, although a new strike in the Shetlands area, where several drill rigs are currently working, could make these estimates invalid in a matter of weeks. Current estimates of proved and economically-recoverable reserves are considerably more conservative than the "ultimate reserves" cited above. 1974 reserve estimates oil (south of 62^{O} N) — 28.4 billion bbl; and gas (south of 62^{O} N) — 198 trillion cubic feet.

Division of development jurisdictions in the North Sea was based on a "median line principle" before the extent of the resources became apparent. The U.K. and Norway emerged with the bulk of the Continental Shelf and the reserves. Denmark and West Germany did poorly. The Netherlands acquired still more gas reserves.

2.2.2 Western European Coal

Western Europe's coal reserves, given current rates of consumption and demand, would sustain the EEC(9) for about one thousand years. If the crude oil energy equivalent of coal is taken as a basis of comparison, Western Europe's coal is the equivalent of two hundred years of EEC(9) oil consumption at 1972 levels. Coal is obviously a major and significant resource. Given the geopolitical and economic climate of 1975 it is a resource that should no longer be neglected.

2.3 LOCATIONS OF MAJOR WESTERN EUROPEAN ENERGY RESERVES

2.3.1 Crude Oil — North Sea

There are 28.4 billion bbls of proved reserves currently under development. The following developmental activities represent

the 1974 allocation of these reserves:

- 55 percent of the reserves are in the U.K. sector. Reserve estimates will grow with additional exploration, but proportional share in the U.K. sector is expected to drop to approximately 50 percent. Extensive exploration is in progress, but slowed early in 1975.

- 45 percent of current reserves are in the Norwegian sector. Reserves are expected to grow, although exploration is slow. A proportional share of reserves is expected to expand to greater than 45 percent, approaching 50 percent as the area north of 62° N is explored.

- Less than 1 percent lies in the Danish sector. Proportional allocation expected to hold at about the same level, as exploration results have been disappointing. There were several dry holes in 1974.

2.3.2 Crude Oil — Inland Continental Europe

Austria, West Germany and Italy have small but significant fields with estimated total reserves of a little over 2 billion bbls in highly scattered small fields.

2.3.3 Gas — North Sea

Subject to similar economic and development constraints, North Sea gas reserves are estimated at 198 trillion cubic feet, with ultimately recoverable reserves estimated as high as 400 trillion cubic feet. Based on the proved reserves estimates, and excluding the Gronigen field of the Netherlands, which extends offshore, the distribution of the North Sea gas reserves is approximately as follows:

- 40 percent lies in the U.K. sector (south of 62° N).

- 13 percent lies in the Norwegian sector south of 62° N. This figure is assumed to be low because of the slow pace of exploration and development.

- 46 percent lies in the Netherlands North Sea waters. This figure, as a percentage of the total, will decline since exploration in the vicinity of the Gronigen and extension of gas formations into the Netherlands North Sea has been extensive.

A 1980 estimate of the shares would be: U.K. – 40%; Norway – 40%; and the Netherlands – 20%.

2.3.4 Gas – Inland Europe

90 trillion cubic feet are estimated to be recoverable in Gronigen (70 proved, additional 20 expected available). Numerous small, but locally significant fields are located throughout the continent and the U.K. but total less than 2 percent of the European supply.

2.3.5 Coal

Coal reserves are distributed throughout Europe and the U.K. and are assumed to be economically recoverable to the 1200 meter level. Current totals are approximately 300,000 million metric tons. If, with advanced mining technology, mining is extended to the 2000 meter level, these reserve estimates double.

2.4 PROMISES OF THE NORTH SEA

The discoveries of oil and gas in the North Sea, occurring as they did before the embargo of 1973/74, gave Western Europe a strong and viable hope of achieving a measure of energy independence from middle-eastern domination of world crude supplies and prices. This premise remains essentially valid, although serious economic problems have attenuated the hope of "cheap oil and gas on Europe's doorstep." North Sea oil may be close to OPEC prices when it begins to come ashore in quantity since prices reflect both very high costs

of operation and amortization of the very expensive transportation and development systems that are needed to exploit the extensive offshore reserves. Nonetheless, the promises of the North Sea may be summed up, in the context of the economic situation of January/February 1975, as follows:

- Reserve estimates have escalated with every successful development well completion and represent viable hope for a large measure of energy independence.

- North Sea reserves were once thought capable of granting the U.K. energy self-sufficiency by 1980-1981. Inflation and other economic factors, political problems, and industrial unrest had, by January 1975, moved this goal to later in the decade.

- North Sea and Netherlands Gronigen gas will continue to make an ever increasing contribution to the economic and industrial systems of all of Western Europe.

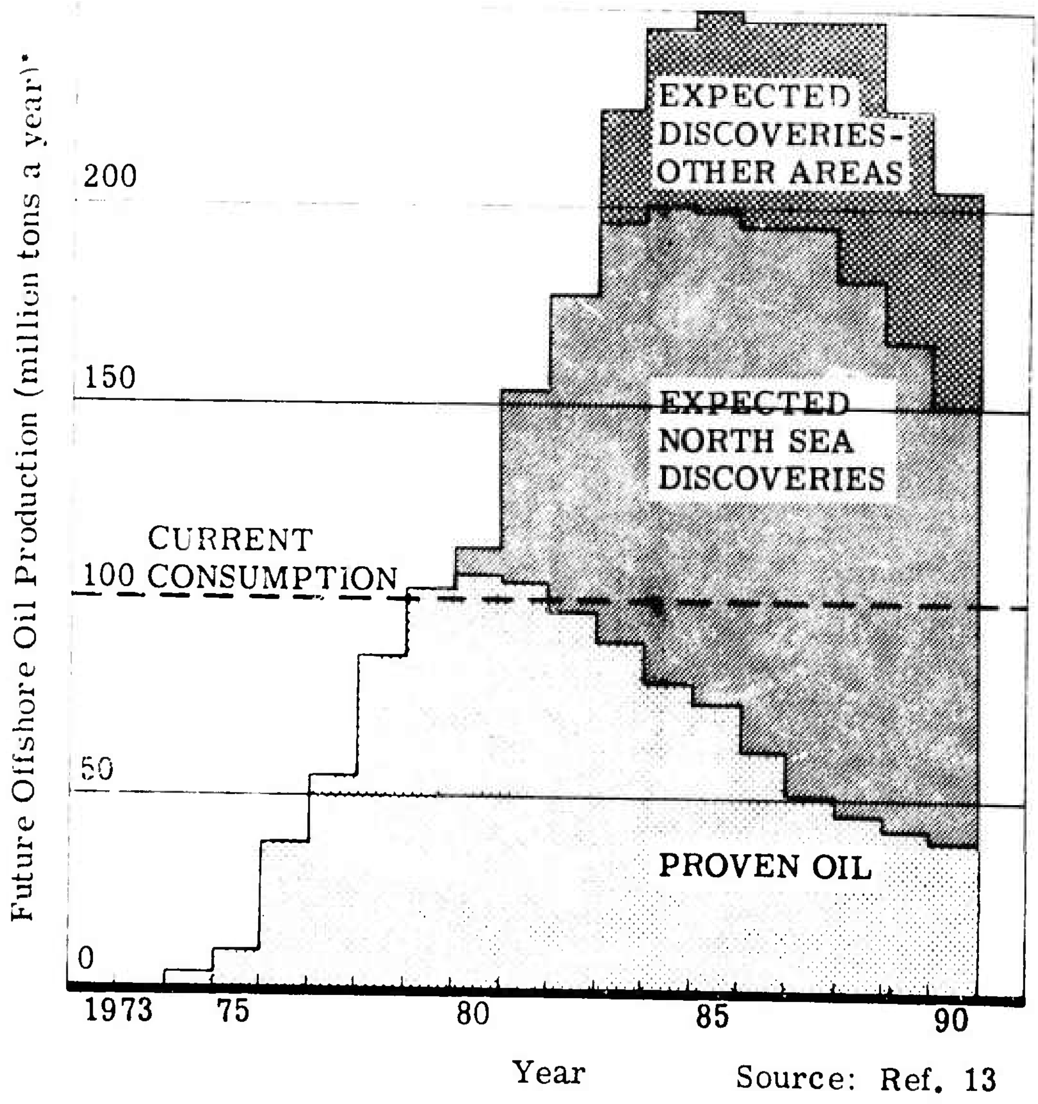
- Despite severely escalating development and production costs, $8-10/bbl North Sea oil will probably be competitive with OPEC crude.

- Earlier "non-commercial" discoveries may be considered viable in view of world crude (and gas) price market and price escalation.

Early in 1974, and before the assumption of power of the current U.K. Labour Government (with associated threats of high taxation and nationalization of large sectors of the oil industry), the Economist[13] published the accompanying chart. It is an optimistic and ebullient view of the U.K.'s opportunities for self-sufficiency and for even becoming an oil exporting nation (Figure 2.3). Problems that subsequently dominated North Sea developments deflated this optimism.

2.5 PROBLEMS IN NORTH SEA AND GAS DEVELOPMENT

The glowing promises of rapid energy independence for Europe, based on development of North Sea oil and gas, rapidly gave way to



* 100 Million Tons Per Year = 2 Million Barrels Per Day

Figure 2.3. Optimistic View of U.K. Oil Position, Published in The Economist in May 1974

the harsh realities of the situation, compounded by worldwide economic factors, many of which were triggered by the 1973 embargo, and over which there appeared to be little or no control. The United Kingdom needed the oil the most, and encountered the most setbacks. Some may charitably be considered "self-inflicted wounds" from the newly elected Labour Government's proposed taxation and nationalization policies. Others were inherent in the nature of the British industrial society which has been plagued by strikes and industrial unrest for generations. From world inflation there appeared to be no immediate solution, and another influence, the North Sea weather, should hardly have been a surprise to those attempting to operate there. The drastic slowdown in U.K. development of the North Sea is summarized in the following paragraphs.

2.5.1 U.K. Slowdown — Causes

The primary cause of development slowdown was the reluctance of firms and investors, ranging from the small U.K. and foreign independent developers (some of whom had banded into development consortia) to the giants such as BP and Burmah (now bankrupt and in receivership), to invest if their profits were to be unconscionably taxed. A proposed Labour Government taxation plan would have effectively put the small firms out of business, and would have only left the developers and operators of the major fields. Sufficient outcries arose after this plan was cited that the Ministry of Energy retreated from this somewhat draconian position, but not to a sufficient degree to encourage exploration and development to retrieve its previous momentum.

A second cause was the degree of proposed government participation in North Sea oil development. Obviously, the larger

the government share, the smaller the share and hence the profits of the developers. The government is, at this writing, taking active steps to nationalize the platform-building industry, a procedure that does not please the Scots who feel already that "England" is taking the major portion of "Scotland's oil profits." New orders have begun to flow in increasing volume to Norway. A third cause was the world-wide malady of "tight money." Although this is a lessening threat, U.K. and world bankers have been reluctant to provide the funds for North Sea development projects.

The soaring costs of North Sea development were mind-boggling during the 1973-1974 period. Costs of labor, materials, services and equipment escalated in concert with world-wide inflation. Special additional costs were incurred as a result of strikes with favorable wage settlements thus massively increasing the labor component of platform and drill-rig fabrication. Maritime costs on work and supply vessels rose dramatically. A few examples, based on the estimated production of typical fields, such as the Forties or Auk, are shown below. The figures represent completely amortized development costs, once the crude starts ashore via pipeline, including exploration, development, production drilling, and the transportation infrastructure to shore.

- In 1970, the estimate of $1000 per bbl per day (BPD) was estimated to develop a field into production status.*
- By early 1973 costs had escalated to $2500/BPD.
- By the end of 1974 costs had risen, in some fields, to $3000/BPD and were still rising.

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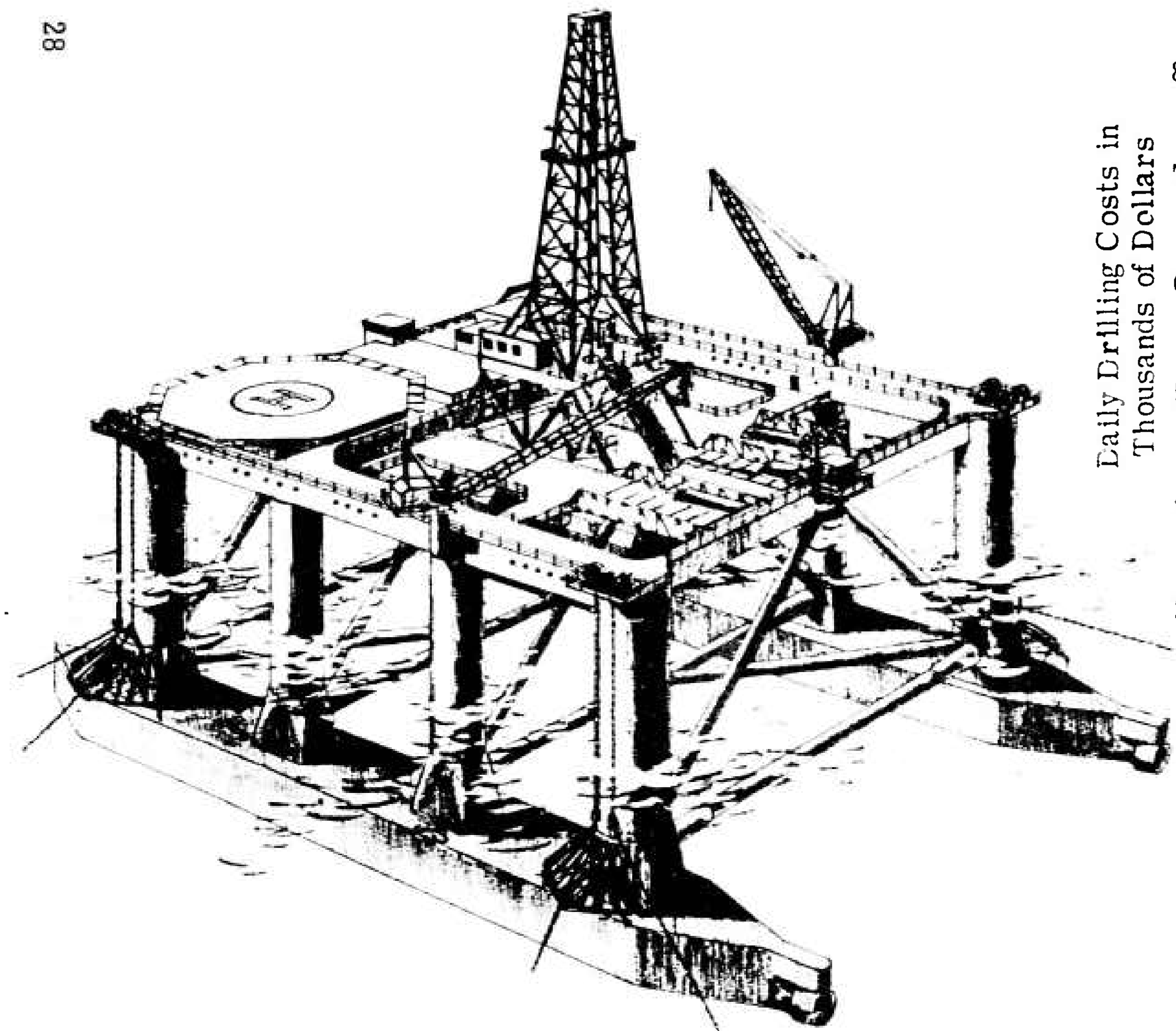
* Cost elements which are included are described in the footnote on page A-15.

In all fairness, it must be pointed out that the "easy" fields (those in shallow waters generally close to the coast and suited for the operation of jack-up rigs) had already been developed. Deep water operations, involving $5 million semi-submersibles (Figure 2.4) were more costly than previously estimated. In like manner, installation of platforms of skyscraper dimensions in deep water (Figure 2.5) became operations costing $100 million per platform and even more.

A final, but not unexpected cause of delays in U.K. development of oil and gas has been the weather. Although U.K. and multinational firms have been engaged in offshore oil exploration and development for several decades, they were totally unprepared for the severe weather constraints occurring in the North Sea. Rigs used in the Gulf of Mexico and extrapolations from such designs, which had previously been used world-wide, were badly suited for the North Sea, where the statistical "100-year storm" (against which the rigs were designed) occurred almost every year. Despite heave compensators on the rigs which allowed drilling to continue with an almost unheard-of 18 foot vertical displacement, rig downtime because of weather was economically devastating, particularly in 1973. Not only did the rigs cease operating and go to a "survival mode" for a large portion of the time, but their logistic support, workboats, supplies of drilling mud, pipe, etc. were unable to operate and transfer their cargoes in seas that commonly ran to 30 and 40 feet. Waves from 65 to 100 feet were not uncommon. Some advanced-technology semi-submersible rigs were destroyed or heavily damaged — one brand new semi-submersible was completely overturned in a savage storm. Weather is a predictable constraint, but it was not properly incorporated in advanced planning, and thus was a significant cause of serious delays in U.K. development of the North Sea.



Semi-Submersible

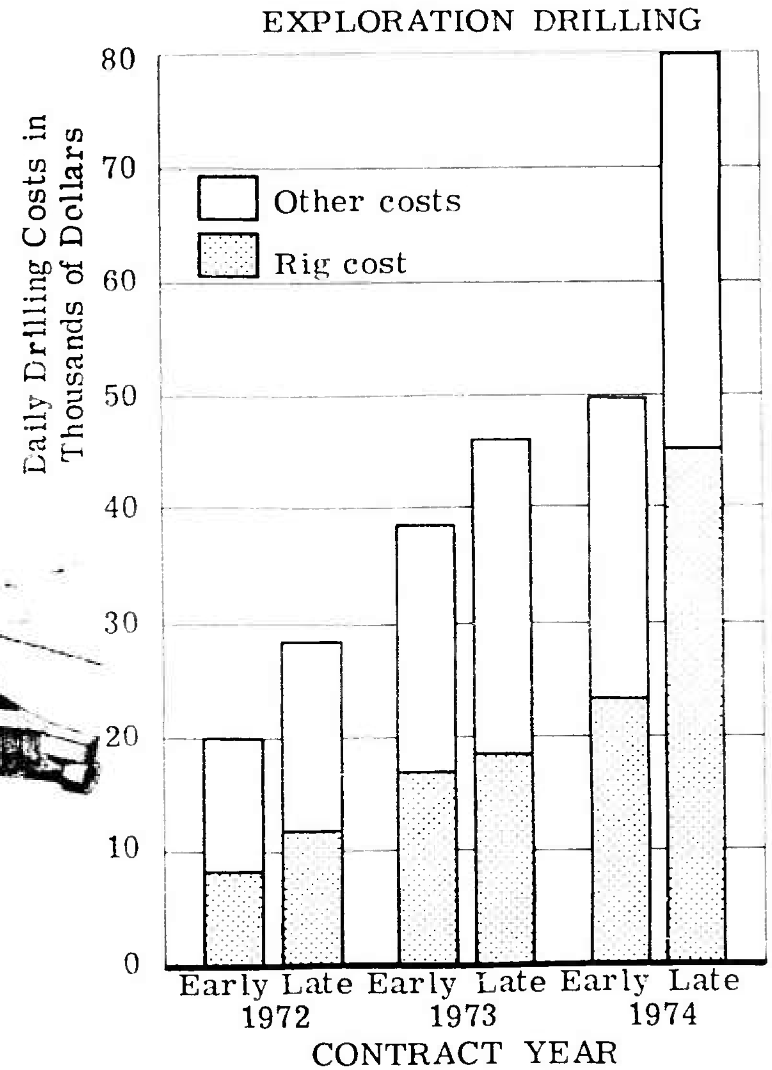


Figure 2.4. Rise of Drilling Costs in the North Sea

PLATFORM

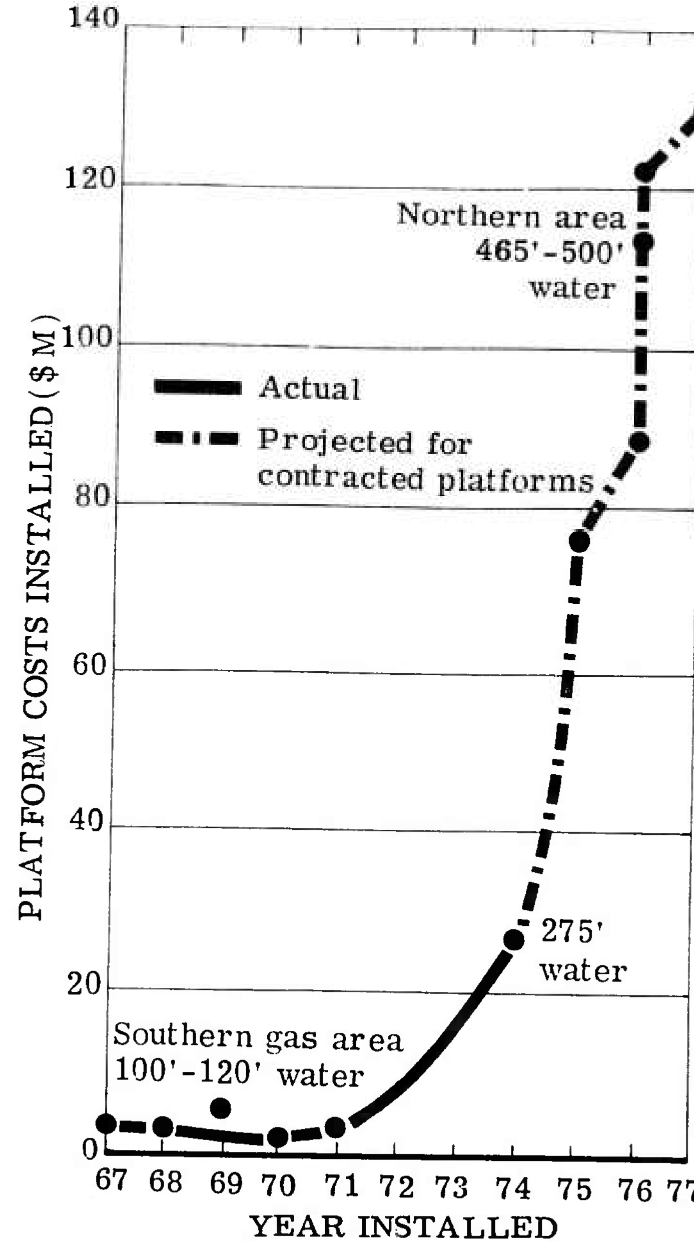


Figure 2.5. North Sea Platform Cost Escalations

2.5.2 U.K. Slowdown — Effects

The effects of the 1973/74 slowdown of U.K. development are summarized below:

- The initial forecasts of "energy independence by 1980" became invalid; 1990 became more realistic.

- The incentive to convert energy and industrial facilities from coal to oil or gas slackened. New coal-fired plants were planned and some previously targeted for oil or gas use were changed to coal. The significance of the U.K. coal industry received new emphasis.

- Major investors in the North Sea threatened to pull out in light of the Labour Government's plans for government participation in development, size of government shares, and taxes on production. Investment slowed, and continues to slow. International and multinational financial support is weakened.

- The U.K. balance of payments remained critical, as projected North Sea oil and gas was not to be available on schedule.

- U.K. industry felt the impact of higher OPEC prices, rather than planned lower prices of North Sea oil and gas.

- A U.K. energy conservation program was initiated — it was previously considered unnecessary.

- Returns on equipment and development investments were seriously delayed as North Sea oil was still unable to pay for itself.

2.5.3 Norway's New Constraints

The U.K. was not alone in a slowdown in North Sea development. Norway held back, too, but for different reasons:

- Norway, a nation of only 4 million, was moving to the role of an oil-exporting nation.

- Norway wished to institute a "go-slow" policy to develop her reserves as the transportation and development infrastructure (storage facilities, platforms, and pipelines) became available.

- In addition to a "go-slow" practice on leases, Norway has proposed up to 90 percent taxation on the private sector's share of profits made by exploitation of Norwegian oil and gas. Several backers of yet-undeveloped concessions have either withdrawn, or have threatened to do so in light of this proposal. A parallel to the public vs private sector adversary relationship began to develop.

2.5.4 North Sea Summary

North Sea oil and gas are a vital resource to all of Western Europe. A summary of the situation as of January 1975 follows:

- North Sea will be developed, but at enormous costs.

- Equipment shortage abates, but exploration rate slackens.

- Bankers are taking a hard look at costs of development. A policy of "tight money" has developed.

- U.K. wishes to go "all out" in development, but has imposed many constraints; Norway is holding back until transport and delivery systems are developed for existing finds.

- 1975 promises to be a year of slowdown and retrenchment in the North Sea.

- Netherlands is doing well with North Sea gas, but has had no commercial oil finds.

- Denmark has not done as well as expected. A series of dry holes were drilled in her sector (1973/74), and she is losing backers.

- West Germany has achieved no commercial finds of either oil or gas in her sector, but is engaged in co-operative ventures in other sectors (e.g., gas from Netherlands and Norwegian sectors).

- North Sea developments have accelerated a massive inter-European pipeline network so that "boundaries" of reserves are essentially moot in the use of North Sea resources.

- North Sea oil is a route to energy self-sufficiency, but is no bargain and may cost as much as OPEC oil when it starts to flow in quantity.

2.6 ADDITIONAL EUROPEAN OIL AND GAS RESOURCES

As discussed more fully in Appendix A, additional oil and gas resources are available, albeit in quantities far below those available in the North Sea, from inland fields, some of which have been operational for several decades. Of these, West Germany has the largest proved inland reserves (approximately 550 million bbl), trailed by Spain, Austria, the Netherlands, and France. None of the fields are large by U.S. or middle-eastern standards, and production is expected to decline at rates parallel to smaller fields in the U.S. and elsewhere in the world, as few, if any, new wells are being brought in. Reserves are substantial, however, and, given the right price and incentive structures, could be responsive to enhanced recovery techniques. Spain and Italy are actively developing new offshore fields in the Mediterranean and the Adriatic, respectively, and within the past month Italy has developed promising oil shows in the Po valley. Tables 2.1 and 2.2, repeated from Appendix A, indicate oil and gas reserves and production forecasts (with an estimated rate of depletion over time) for the major countries of Western Europe. It should be noted in Table 2.2 that France expects to sustain, and even increase, domestic natural gas production, based on substantial reserves and on

Table 2.1. Domestic Oil Production and Projections for 1980-1985

Country	Production (1000 bbl/day)		Expected North Sea	Consolidated Domestic Production (1000 bbl/day)		Estimated Reserves (million bbl)
	Current Domestic	Current North Sea		1980	1985	
Austria	47.059	0.0	0.0	34.5	30.0	160.0
Belgium/Lux.	0.0	0.0	Approx. 30% Ekofisk Prod.	0.0	0.0	0.0
Denmark	0.0	4.0	8.0 (Series of dry holes, 1973/74)	8.0	9.0	248.5 (North Sea sector)
France	20.170	0.0	0.0	18.0	17.0	142.0
W. Germany	117.595	0.0	Unknown (no rigs working)	81.0	66.0	550.0
Italy	18.328	0.0	0.0	12.0	10.0***	750.0***
Netherlands	27.391	0.0	Unknown (one small field not developed — emphasis on goal)	24.0	21.0*	251.0 (North Sea sector not included)
Norway	0.0	30.0	>1500.0 (Depending on rate of development and export)	200.0	500.0	1000.0 (North Sea sector)
Spain	37.430	0.0	0.0	45.0****	50.0	293.0
United Kingdom	1.5	40.0	>3000.0 (Including Norwegian sector production)	480.0	600.0	1300.0 (Primarily North Sea sector)

* Secondary and tertiary recovery systems may reactivate shut-in or low-level producing wells if world price is high enough

** Germany has not pursued an active exploration-drilling program, but has done extensive seismic work in North Sea. Reserves cited do not include North Sea potential, not yet established, but are limited to inland fields.

*** New offshore discoveries in Adriatic look promising. Po valley 1975 discoveries not included.

****New Mediterranean fields established, initial wells working. Greater activity expected in next decade.

Table 2.2. Domestic Natural Gas Production and Projections for 1980-1985

Country*	Production (million cubic feet per day**)		Expected North Sea	Consolidated Domestic Production (Includes direct supply from North Sea)		Estimated Reserves
	Current Domestic	Current North Sea		1980	1985	(billion cu ft)
Austria	191.7	-0-	-0-	148.3	114.8	None
Belgium	-0-	-0-	Will share in Ekofisk at approx. 1,100	None directly, except third country		None
Denmark	-0-	-0-	Unknown, generally favorable structures	Unknown pending further North Sea expl.		1,800 (North Sea sector)
France**	715.0	-0-	Indirect through third country imports	946.0	946.0	6,500
W. Germany	1,650.0	-0-	600 from Norwegian and Netherlands fields in North Sea	2,143.3 + 200 N/S?	1,840.0 + 400 N/S?	12,308
Italy	1,400.0	-0-	North Sea plus Gronigen indirectly	1,434.0	1,487.0	5,300
Netherlands	6,900.0	-0-	600 firm plus development of adjacent structures	8,000.0	3,500.0	94,800
Norway	-0-	-0-	2,600 plus other discoveries not yet in development stage	2,600.0 + ??	3,200.0 + ??	23,000 + extensive N/S not proven
Spain	-0-	-0-	-0-	0 (only if gas is found in commercial quantities in Mediterranean oil exploration)		500
United Kingdom	Minimal	3,300	4,800 + Imports from Norwegian sector and new discoveries	5,200.0+	5,200.0+	50,000

* Natural gas energy content: France, $3.25 \cdot 10^5$ kcal/ft^3
Italy, $3.21 \cdot 10^5$ kcal/ft^3
Others, $2.96 \cdot 10^5$ kcal/ft^3

**Ref.: Commission of the European Community, "Medium-term Prospects and Guidelines in the Community Gas Sector," Brussels, 1972.(14) See also text comments.

government encouragement of further development and exploitation of existing fields and promising structures.

2.7 COAL RESOURCES OF WESTERN EUROPE

A detailed discussion of the status and future of coal resources of Western Europe is presented in Appendix A. This section is limited to an overview and a discussion of present and potential trends.

2.7.1 Background

As previously mentioned, coal has historically been the backbone of European industry and the source of the greatest portion of its energy generation capability. However, after World War II, oil and gas largely replaced coal in the commercial and residential sectors of the economy, and oil in particular was making heavy inroads into the industrial sector. With the discovery of the Gronigen gas fields, gas was replacing coal in all sectors of the economy except metallurgical coal for the iron and steel industry. However, domestic coal retained a firm base in the iron and steel industries, supplemented by imported coal from within and without Europe.

The metallurgical industries provide a firm production base for the current Western European coal industry -- however, as a result of oil and gas inroads in the commercial, residential, and balance of the industrial sector, Western Europe's coal industry is declining sharply. In addition to lessened demand, many other factors are contributing to this decline. A primary cause is operating, at a loss, expensive, labor-intensive, non-profitable mines. Many marginal mines are located in unfavorable geologic structures,

thus making them more labor-intensive. However, the labor force is diminishing. Fewer new workers enter mining, and the older labor force is retiring. The new supply does not make up for losses in manpower, particularly of trained workers. This trend cannot be reversed in short order, even if a depressed economy makes mine labor attractive as a source of income.

2.7.2 Resources and Production

Table 2.3, also shown in Appendix A, summarizes the production status and trends expected in Western European coal. The following should be noted:

- Non-economic mines and complexes are being phased out, either completely and nationally as in the case of the Netherlands, or partially as in the case of Belgium, France, and Germany.

- In France and West Germany, the decline is expected to level out, aided by phaseout of non-economic mines and government subsidies. Metallurgical coal is a must, from either imports (using foreign exchange) or domestic sources. The slow pace of nuclear development and the increasing price of imported coal has caused many new lignite-fired thermal power plants to be built, particularly in West Germany. Efficient and reasonably profitable mines will be kept in operation by government subsidy.

- In the U.K., the National Coal Board, operator of the country's nationalized mines, has established as a national policy a goal of production level throughout the next decade of 120-150 million tons per year. Strikes have made the achievement of this goal difficult. The current economic situation does not offer any significant change in the situation.

- West Germany is emerging as the EEC(9) supplier of both metallurgical and thermal coal for Western Europe. Other suppliers, external to the EEC(9), are Poland, U.S.A., U.S.S.R., Canada, and Australia.

Table 2.3. Domestic Coal Production and Projections for 1980-1985

Country	1973 Production of Both Hard and Soft Coal (million metric tons)		Economically Recoverable Reserves (million metric tons)		Estimated Future Production (million metric tons)		Remarks
	Anth. & Bit.	Sub-bit. & Lig.*	Hard Coal	Soft Coal	1980	1985	
Austria	Negligible		---	64	Continued	Negligible	Historical decline expected to continue unless price of oil becomes completely untenable, and exploitation of reserves becomes an attractive option.
Belgium/Lux.	8.8	---	253	---	6.8	5.4	Historical decline expected to continue but rate of decline will decrease. Natural gas expected to continue to replace coal in industrial and commercial use.
France	25.7	0.9	443	15	28.0	30.0	France is concentrating on more productive mines, with a decreased labor force. Energy problems, and no North Sea resources should encourage the achievement of government-stated goals.
W. Germany	97.3	36.0	30,000	9,571	95.0	95.0	Current plans are to stabilize production at 95 million ton level, with the closing of inefficient mines. New expansion of facilities will be required to increase production significantly, as subsidies are currently required. Oil prices may force a decision in 1975.
Greece	Negligible		---	150	Negligible		New offshore oil finds further tend to negate role of coal.
Italy	0.1	0.4	---	33	Negligible		Extensive government support required which is not foreseen with current oil/economic crisis.
Netherlands	1.7	---	1,843	---	1.0	0.5	Government plans to close all mines and use extensive natural gas reserves.
Spain	9.9	(3.1)	453	1,190	8.0	7.0	A relatively "poor" country with a large labor force, Spain may well keep a coal industry as a viable energy option.
United Kingdom	129.9	---	3,870	---	130.0	130.0	Objective is to "stabilize" in the face of increasing demands and the exhausting of a large number of marginal mines. Estimates are based on a "120-150" million ton domestic demand by 1985, and realistically considered in the context of strikes, economic problems, etc. that traditionally cause failure to meet planned goals.

*Hard coal equivalent

- A new look is being taken at deep reserves (2000 meters) where extensive additional reserves of coal throughout Western Europe lie. Extensive mechanized mining would be required to exploit these deposits.

2.8 ENERGY AVAILABILITY PROJECTIONS

The considerable gap between the energy resources of Western Europe and expected consumption will be discussed in Section 3. After the discussion and analyses of energy resources were concluded (see Appendix A and the summary in the first portions of this section), the potential for energy imports from non-OPEC sources was established. The current situation (firm 1973 data adjusted to 1974 where available) for the largest importing nations for the three primary energy sources (coal, natural gas, and oil) is presented in Table 2.4. The role of the U. S. S. R. as the primary, non-OPEC supplier of crude oil and natural gas (via newly constructed pipelines) becomes apparent and Poland emerges as a major supplier of coal.

For purposes of this study, the same levels of imports are projected for 1980-1985. Uncertainties in non-OPEC supplies exist, since these imports could be impacted by increased domestic demands of the suppliers (e.g., increased use of coal in the U. S. A. — a national energy objective — and continued industrialization of Poland). Therefore, the 1973 import pattern of the primary energy fuels has been maintained, and added to projected source availability in the 1980-1985 period to produce Table 2.5. In order to establish a common energy datum, million tons of oil equivalent (MTOE) is used in the presentation of projected fuel availability of coal and natural gas.

Table 2.4. Current Non-OPEC Import Levels

Country	Coal (1000 metric tons/year)		Natural Gas* (MM/cfd)		Oil (bbl/day)		Remarks
	Quantity	Primary Source	Quantity	Source	Quantity	Source	
Austria	2,803	W. Germany Poland U.S.A.	145	U.S.S.R.	20,000	U.S.S.R.	New pipeline from U.S.S.R. to double gas supplies
Belgium/Lux.	7,486	W. Germany (3300)**	300	Netherlands	Primarily OPEC		Additional 1,500 MM/cfd gas to be acquired from Ekofisk as member of European Consortium.
Denmark	3,064	Poland	Uses manufactured gas		Primarily OPEC		Danish rate of consumption of oil/gas does not warrant pipelines at current prices.
France	12,499	W. Germany (5900) Poland U.S.A.	783 387 230	Netherlands U.S.S.R. North Sea	70,000	U.S.S.R.	Joint with W. Germany on pipeline from U.S.S.R. by 1980.
W. Germany	7,100	Poland U.K. U.S.A.	1,400 50 (667) (800)	Netherlands U.S.S.R. U.S.S.R. -1980 Norway & Netherlands 1975/76 (North Sea)	Primarily OPEC		Thermal coal imported; metallurgical coal retained for industry and export. Heavy emphasis on development of guaranteed natural gas-based manufacturing capability. Gas figures in brackets represent firm delivery contracts with the U.S.S.R. and North Sea sources.
Italy	11,705	U.S.A. Poland W. Germany (2800) U.S.S.R.	600 600	U.S.S.R. ('75) Netherlands (1976/77)	Primarily OPEC		Both U.S.S.R. and Netherlands pipelines are under contract and are expected to be operational (20-year contract) by 1975, but may slip with materials shortages and higher costs.
Netherlands	3,200	W. Germany (1000)	Domestic Sources		Primarily OPEC		Netherlands phasing out coal for gas. Oil acquired by trade agreements (usually OPEC oil) in exchange for gas. Minimal oil in Netherlands North Sea sector, but may slightly lessen dependence on imported oil.
Norway	412	U.K.	Uses manufactured gas		Domestic Sources (North Sea)		Norway will become oil exporting country as soon as production/transportation infrastructure is established. Pipeline from North Sea fields under study — Norwegian Trench makes construction difficult and expensive.
Spain	3,056	Poland U.S.A.	Pipeline planned from France		Primarily OPEC		Coal imports up sharply in past decade with increased industrialization.
United Kingdom	1,676	Poland Australia	Domestic and North Sea sources		Currently primarily OPEC, approx. 60,000 bbl/day from mix of U.K. and Norway North Sea fields		Additional North Sea oil and gas developments in the U.K. sector expected to bring 1,500 MM/cfd gas in 1975/76. Oil pipelines from three major North Sea fields expected in post-1976 period, and despite delays to give U.K. oil independence by 1983.

*Imported LNG is considered an OPED energy source and is not included herein.

**West German coal exports to Western European countries excluded from potential sources of coal imports.

Table 2.5. Projected Fuel Availability for EEC(9)
(10^{13} Kilocalories)

Country	Coal				Gas				Oil	
	1980		1985		1980		1985		1980	1985
	Domestic	Imports*	Domestic	Imports*	Domestic	Imports*	Domestic	Imports*	Domestic	Domestic
Germany	91.7	---	91.7	---	20.4	12.7	19.5	12.7	4.2	3.4
France	20.2	4.7	21.6	4.7	9.0	5.4	9.0	5.4	0.9	0.9
U.K./Ireland	92.2	---	92.2	---	41.7	---	45.2	---	24.8	31.0
Italy	0.4	6.3	0.4	6.3	13.5	5.6	14.0	5.6	0.6	0.5
Denmark	---	2.1	---	2.1	---	---	---	---	0.4	0.5
Netherlands	0.7	1.5	0.4	1.5	69.5	---	73.8	---	1.2	1.1
Belgium/Lux.	4.8	2.9	3.8	2.9	13.0	---	13.0	---	1.2	1.1
EEC(9) Total	210.0	17.5	210.1	17.5	190.8	23.7	198.2	23.7	33.3	38.5

*Imports from OPEC and EEC member countries excluded.

Section 3

ENERGY DEMAND PROJECTIONS

3.1 METHODOLOGY AND ECONOMIC RATIONALE

3.1.1 Overview of the Approach

The traditional approach to the projection of future energy demands has been to project (or assume) a growth rate of GNP by country and then to relate the growth of GNP to the growth of broad energy consuming sectors. Given projections of the growth of the energy consuming sectors, energy use in these sectors can be projected on the basis of observed relationships between the level of activity in each sector and the level of energy use in each sector. Such projections take into account trends in the relationships between energy use and the levels of sectoral activity. Finally, to obtain future estimates of the quantity of energy use broken down by energy source (e.g., oil, natural gas, and coal) the energy demanded by sector is allocated among various sources on the basis of data on cost, availability of supplies, technical considerations, and national energy policy (e.g., the policy pursued by France to push the conversion to nuclear generation of electricity).

The practice of forecasting future energy use by relating it to future economic growth can be justified because of the high correlation within countries between the growth of GNP and the growth of energy demanded. This relation, however, has been markedly

different among countries and has been different within individual countries for different periods in time. The most important reasons for these observed differences are:

1. Differences in the level of economic development;
2. Differences in industrial composition;
3. Differences in levels of personal income;
4. Changes in technology over time; and
5. Changes in the relative price (cost) of alternative sources of energy and energy forms.

Countries with low levels of economic development have low ratios of energy use to GNP as compared with highly developed, industrialized countries. Among the developed countries, those such as Luxembourg with a large steel industry have a high energy to GNP ratio as compared with Switzerland which produces pharmaceuticals and precision watches. As one would expect, the level of direct energy use by individuals is related to the level of personal income. Further, technological changes appear to have played a significant role in affecting the relationship between GNP and energy use. Improvements in the efficiency of engines in the transportation sector and in the generation of electricity all have tended to lower the energy use to GNP ratio as they were being introduced, offsetting in many developed countries the effects of increased industrialization, a larger transportation sector, and higher personal incomes.

Finally, changes in the relative price of energy as compared with other products and changes in the relative price of various sources of energy (e.g., oil as compared with coal) affect both the quantity of total energy demanded and the distribution of this demand

among various energy sources. Most of the differences in the relations between energy use and GNP mentioned above can be accounted for by breaking down energy demand by broad consuming sector. The one exception is the change in the relative price of energy. Since there has been a dramatic increase in the price of oil, the effect of this price increase on future energy consumption is of primary importance for our projections in terms both of the level of energy consumed and distribution of this demand among energy source. Of particular interest is the role of imported crude oil in the supply of Western Europe energy demand.

A two-step process was used to project the amount of energy demanded by OECD Europe, by the EEC(9), and by individual countries. The first step was to develop pre-embargo projections of the quantity of energy demanded by the various countries and by Western Europe as a whole through the year 1985. The method for these projections in general was:

1. To assume continued growth of GNP within each country at rates comparable to those of the past few years;

2. To break the projections of GNP into broad consuming sectors by country and to assume that trends in energy use during the period 1960-1970 would continue; and

3. To assume that the pre-embargo oil price of $3/bbl in the Persian Gulf would continue until 1985.

The reason for making this last assumption, which we know to be incorrect, is that it allows us to develop projections based on past trends in energy use that have shown a high degree of stability over time, barring major price changes. The reason for using trends in energy use from 1960-1970 is that there appears to have been a shift in these trends about 1960. The second step in the procedure is to

modify the pre-embargo projections to take into account the effect of the increase in price of Persian Gulf oil. This was done by applying demand elasticities to the various categories of energy demand.

To summarize, the method of projecting energy use in Western Europe consisted of:

1. Projecting energy use by energy consuming sector and by energy source using projected rates of growth in GNP and its split among sectors, assuming no significant change in energy prices; and

2. Modifying these projections for changes resulting from the increase in the price of imported oil.

3.1.2 The Procedure

In developing the projections of sectoral growth and energy consumption by source within countries, the national policies and economic plans of the individual countries must be reflected. This requires both intimate knowledge of these policies and an ability to exercise judgement about changes that may occur in the growth of energy consuming or producing sectors as a result of national economic policy. For this reason, in developing pre-embargo projections we have relied, wherever possible, on sources of data and projections of growth and energy use developed by responsible planning agencies within individual countries, the EEC, and OECD. One of the key tasks was to put the information from the various sources on a consistent basis in a common format, as discussed in Section 1.3. The information sources on which the projections have been based were discussed in Section 1.4.

The second step in the process was to adjust demand figures for changes in the price of oil in the Persian Gulf. The concept that

economists use to relate changes in the amount demanded to changes in price is that of the demand elasticity which measures the percentage change in the amount demanded as a result of a 1 percent change in the price. However, since we were not only interested in the effect of an increase in the price of oil on the amount of oil consumed, but also on the total amount of energy consumed from other energy sources (e.g., coal, nuclear), we also needed estimates of the cross-elasticity of demand which measure changes in the amount demanded of other energy sources as a result of a change in the price of oil. Toward this end, the literature on demand elasticities and cross-elasticities for various forms of energy was reviewed. On the whole, the work in this area does not provide a very satisfactory basis for the purpose of this study. Ideally, one would like to have demand elasticities and cross-elasticities by energy source (i.e., crude oil, coal); however, most estimates of demand elasticities have been made for end products (e.g., there are a number of estimated demand elasticities for gasoline). The relation between the prices and the amounts demanded of refined petroleum products and the demand for crude is complex. There is no simple relationship between the elasticities of petroleum products and crude oil. Finally, reliable estimates of cross-elasticities simply are not available. Given these problems and the fact OECD itself had followed a creditable procedure in projecting future energy demands for OECD as a whole using demand elasticities for energy by consuming sector, we decided to build on their work(7). The elasticities they used were a product of judgement based on analysis of end use elasticity estimates. In addition, the OECD modification of the pre-embargo projections were based on an assumed price of $9/bbl for oil in the Persian Gulf. The demand elasticities for energy by use are given

in Table 3.1. Allocations of part of the decrease in the demand for oil to other energy sources were based on informed judgements since specific cross-elasticities between energy sources were not available.

Table 3.1. Price Elasticities* by Sector

Industry	.25
Transportation	.25
Residential and Commercial	.50
Non-Energy Oil	.11

* Price Elasticity — The percentage change in quantity demanded divided by the percentage change in price.

3.1.3 Qualifications and Potential Sources of Error

There are a number of reasons why future energy demands in Western Europe may deviate from the projected demands. First, oil prices in the Persian Gulf are above the $9/bbl used in applying the demand elasticities to pre-embargo demands. This will have the effect of further reducing the amount of energy demanded, decreasing the demand for oil, and increasing the demand for other energy sources. While the $9/bbl is $1-3/bbl below current Persian Gulf prices, there is evidence that a surplus of oil exists at these prices and that there are strong pressures that may result in price reductions. Small price reductions have already occurred. Further, production cutbacks have fallen unevenly among oil exporting countries and this situation is likely to undermine the price fixing power of OPEC. It seems likely that some further price reductions will be effected so that the $9/bbl assumed in this study may not be too high.

Secondly, the demand elasticities are at best rough estimates, and they must be considered to be long run demand elasticities. This means that the elasticities measure the percentage change in demand

from a change in price that results from the new price remaining in force for some time so that consumers can make adjustments to reduce their use of the relatively more expensive source of energy. In the short term, the possibilities for making adjustments to reduce energy use are fewer, so one would expect the short term demand elasticities, and hence the short term reductions in energy use as a result of an increase in price, to be smaller.

It is instructive to consider these points with regard to the relation between projected energy use and actual energy use for the beginning of 1975. In Figure 3.1 the heavy black line on the graph represents the actual level of energy use and the dotted lines represent the \$3/bbl and \$9/bbl energy use projections. The point marked by an ⊗ is a forecast for 1975 based on data obtained during the last quarter of 1974. Actual consumption, while less than the \$3/bbl projection, is greater than the \$9/bbl projections. This is true even though the actual Persian Gulf oil price is above \$9/bbl. What this suggests is that in the short run the demand elasticities employed in modifying the demand projections are too high. If this is so, one would expect the actual level of energy consumption to approximate more closely the projected level of consumption as more time passes and energy conserving adjustments can be made.

A final qualification is that the procedure used was based on an assumed rate of growth of GNP. If, however, the increased price of energy would have a significant dampening effect on the economic growth rate of various countries, then the projections of energy use at higher prices might have to be revised downward. This effect on the growth rate might come about in two ways. First, it might be true that rate of growth in a full employment economy would be significantly lower with higher energy costs. There is not much

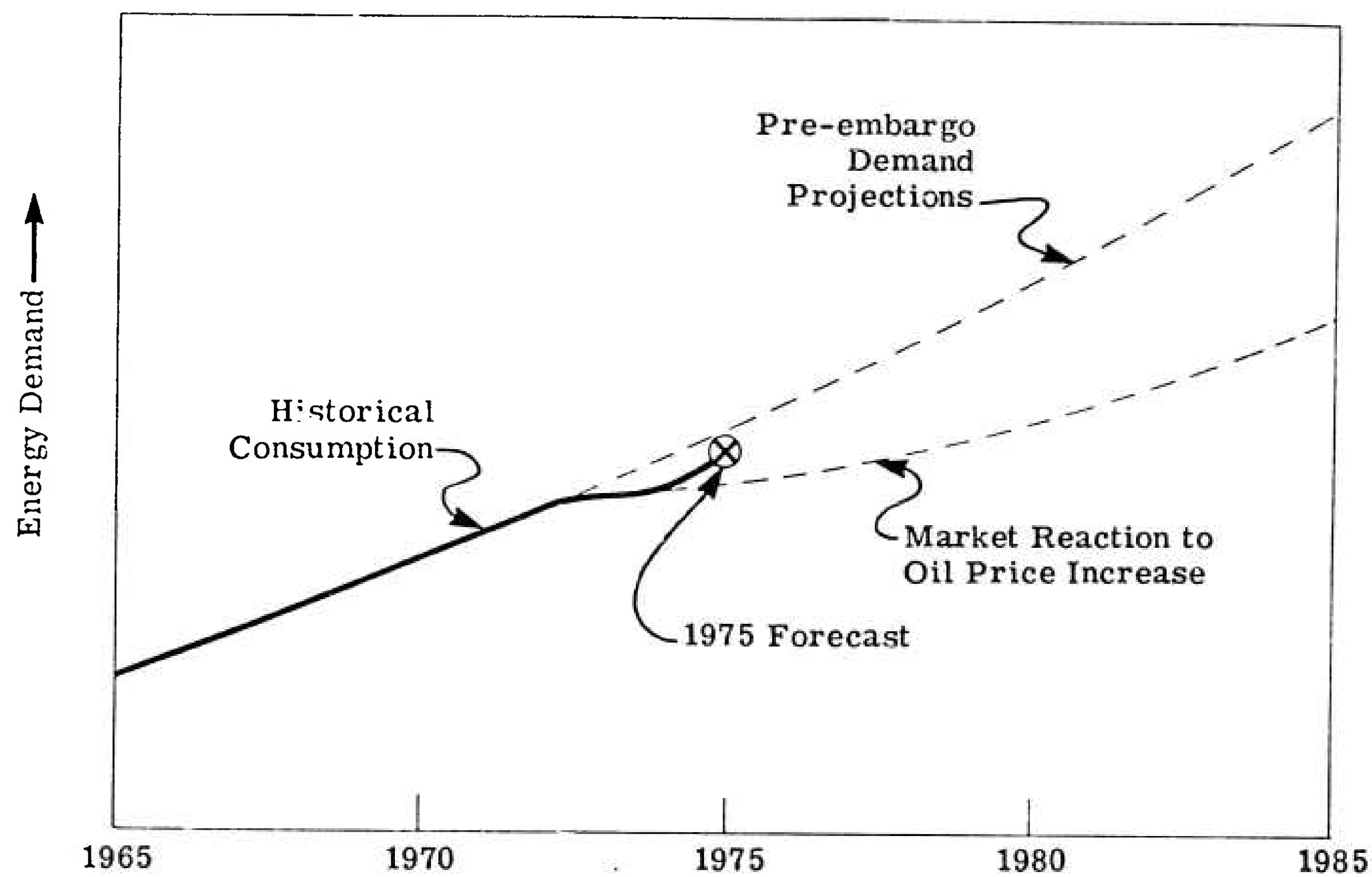


Figure 3.1. Elements of Energy Demand Methodology

evidence on this, but the one work that addresses this question(10) demonstrates that given their model and U.S. data, the effect of a reduction in energy use as a result of price increases will be small. This issue, however, is certainly not resolved. The second possibility, and the one we subsequently will argue in Section 4, is the more serious one; that nations might react to the high price of imported oil by adopting restrictive economic policies and by engaging in programs to attain energy self-sufficiency that will bring about economic recession. To the extent that high energy prices will trigger unemployment and the under-utilization of resources, the protection of energy demand which follows may be high.

3.2 PROJECTIONS

Following the approach outlined in Section 3.1, the first step was to prepare detailed energy balances for a baseline historical year — 1972. This was accomplished using material from OECD and the EEC(9) to produce tables of consumption of each major energy source (solids, oil, natural gas, manufactured gas, and electricity) for each consuming sector (commercial-residential, industry, transportation, non-energy [petrochemical], bunkers, and electricity generation) for OECD Europe, the EEC(9) and its constituent countries. In all of the tables and analyses which follow, Ireland has been combined with the United Kingdom, and Luxembourg with Belgium. All fuels were tabulated on the basis of their energy content and the source data for hard coal, lignite, and coke were converted to a comparable basis. Coal to manufactured gas to coke amounts were analyzed to avoid double counting. Finally, the equivalent energy inputs for generated electric power were developed. This step was vital to calculating the total energy consumed, since all electricity

figures were given in the energy content of the electric power produced. The energy inputs were determined based on the mix of power plants by fuel type, the corresponding conversion efficiencies, and the energy content of the various fuels. Nuclear and hydroelectric power were expressed in terms of their equivalent fossil inputs — this allowed potential shortfalls in the expansion of hydroelectric and nuclear generating plants to be expressed in the fossil fuel required to take up the slack.

The results of this analysis for the baseline year are shown in Table 3.2. As shown, the EEC(9) accounts for 80 percent of the energy consumption of Western Europe and Germany; the U.K. and France combined account for 70 percent of the EEC(9)'s energy consumption. The energy consumed in generating electric power shown in the table has already been accounted for under the various consuming sectors.*

The energy demand projections for 1975 were developed by extrapolating mid-1974 consumption figures by fuel for each country. The assignment of the consumption figures to each consuming sector is in the same proportion as in the pre-embargo projections. The results, summarized in Table 3.3, are observed not to differ greatly from the pre-embargo projections shown in Table 3.4. The total consumption for the EEC(9) is only 4 percent less than earlier projections. The figures for the U.K. are observed to change very little, as a rebound from the coal strike held consumption figures up.

The 1980 and 1985 projections were developed by modifying the OECD and EEC(9) projections prepared prior to the oil embargo.

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*More detailed energy balances by country for 1972 and for the pre-embargo projections for 1975, 1980, and 1985 are given in Appendix C.

Table 3.2. Baseline European Energy Balance — 1972 (10^{13} Kilocalories)

ENTRY	OECD EUROPE	EEC (9)	GERMANY	DENMARK	NETHERLANDS	BELGIUM & LUXEMBOURG	ITALY	FRANCE	U.K. & IRELAND
COAL	250.5	224.5	85.0	1.5	3.2	13.7	8.3	29.4	83.4
OIL	739.6	588.6	139.6	19.1	39.3	33.1	104.7	124.2	128.6
GAS	116.2	112.0	23.9	--	28.7	6.7	14.0	12.8	25.9
HYDRO & NUC	104.0	42.7	8.7	-0.6	N=.075 H=-0.3	0.7	10.3	13.5	10.4
TOTALS	1210.3	967.8	257.2	20.0	70.9	54.2	137.3	179.9	248.3
COMMERCIAL-RESIDENTIAL	393.9	321.1	92.6	9.9	23.9	15.4	37.1	57.9	84.3
INDUSTRY	543.4	425.4	114.0	5.3	24.8	27.6	62.6	78.9	112.2
TRANSPORTATION	169.0	129.3	35.3	2.9	7.4	5.4	19.8	26.4	32.1
NON-ENERGY	56.8	51.6	11.0	1.1	2.3	2.6	9.2	11.4	14.0
BUNKERS	47.2	40.4	4.3	0.8	12.5	3.2	8.6	5.3	5.7
(ELECTRICITY)*	328.8	245.4	71.3	5.4	12.6	10.6	28.3	38.2	79.9

* Not to be included in totals

Table 3.3. Projected Western European Energy Balances — 1975
(10^{13} Kilocalories)

ENTRY	OECD EUROPE	EEC (9)	GERMANY	DENMARK	NETHERLANDS	BELGIUM & LUXEMBOURG	ITALY	FRANCE	U.K. & IRELAND
COAL	249.3	220.7	80.8	4.3	2.1	15.0	9.4	28.4	80.7
OIL	818.6	637.4	139.6	22.9	39.3	34.8	109.9	136.6	154.3
GAS	169.0	164.0	40.6	---	34.4	15.4	19.6	15.1	38.9
HYDRO & NUC	123.0	49.4	9.6	---	0.8	0.6	12.4	13.5	12.5
TOTALS	1359.9	1071.5	270.6	27.2	76.6	65.8	151.3	193.6	286.4
COMMERCIAL-RESIDENTIAL	435.2	349.4	94.0	14.1	21.8	17.4	38.4	58.9	104.8
INDUSTRY	610.6	471.7	124.2	6.6	30.4	34.3	74.1	90.1	112.0
TRANSPORTATION	191.7	146.8	31.8	3.9	7.9	6.2	19.8	25.6	51.6
NON-ENERGY	70.7	61.2	15.5	1.4	3.6	4.1	10.7	13.6	12.3
BUNKERS	51.7	42.4	5.1	1.2	12.9	3.8	8.3	5.4	5.7
(ELECTRICITY)*	375.9	275.9	82.7	5.6	14.4	12.7	34.0	46.6	79.9

* Not to be included in totals

Table 3.4. Pre-Embargo Projection of Western Europe Energy Balance — 1975
(10^{13} Kilocalories)

ENTRY	OECD EUROPE	EEC (9)	GERMANY	DENMARK	NETHERLANDS	BELGIUM & LUXEMBOURG	ITALY	FRANCE	U.K. & IRELAND
COAL	241.1	209.7	83.3	2.9	2.1	14.1	11.2	24.5	71.6
OIL	870.1	702.6	172.3	19.3	49.1	38.6	124.0	137.8	163.5
GAS	150.3	143.5	30.1	---	31.5	8.6	17.5	18.2	37.6
HYDRO & NUC	120.2	56.8	12.8	---	0.7	2.1	13.4	15.5	12.3
TOTALS	1383.7	1114.6	298.5	22.2	83.4	63.4	166.1	196.0	285.0
COMMERCIAL-RESIDENTIAL	443.9	361.9	103.7	11.6	23.8	16.8	42.0	59.6	104.4
INDUSTRY	620.6	492.8	137.0	5.4	33.0	33.1	81.4	91.4	111.5
TRANSPORTATION	195.9	151.4	35.0	3.2	8.6	5.9	21.7	25.8	51.2
NON-ENERGY	71.7	63.8	17.1	1.1	3.9	3.9	11.8	13.7	12.3
BUNKERS	51.6	44.7	5.7	0.9	14.1	3.7	9.2	5.5	5.6
(ELECTRICITY)*	374.2	284.9	81.4	5.3	12.6	12.1	39.3	43.5	91.5

* Not to be included in totals

using the methodology which has been described in Section 3.1. Tables 3.5 and 3.6 show the post- and pre-embargo energy balances for 1980, while Tables 3.7 and 3.8 present the corresponding data for 1985. The remainder of this section discusses the 1980 and 1985 projections in greater detail.

Figure 3.2 shows the historical and projected energy consumption of OECD Europe and the EEC(9). As indicated, the dashed lines demonstrate the difference between the post- and pre-embargo projections. In addition, it can be seen from the estimate for 1975 that the region has not yet fully responded to the pressures introduced by higher energy prices. The corresponding growth rates for the region are given in Table 3.9 — pre-embargo estimates of U.S. and Japanese energy consumption growth are shown for comparative purposes. The impact of the embargo is to cut energy demand growth about in half during the 1975-1980 time period. By 1980, most of the impact has been accommodated so that there is little change for the 1980-1985 time period. The fact that the rate actually increases slightly is due to the fact that prior to the embargo the European community was already planning to reduce its percentage dependence on oil; hence application of the price elasticity of oil to the pre-embargo projections would produce less of a change for 1985 than for 1980. As a result, when the 1980-1985 growth rate is computed for the post-embargo demand, the growth rate will increase.

The composition of the total energy demand of the EEC(9) by fuel is given in Figure 3.3. A prominent feature is the decline in coal from 1962 to 1975, and the continued decline planned through 1985 for the pre-embargo projections. The amount of oil demanded in 1980 and 1985 decreases significantly for the post-embargo case — reduced from above by a decrease in total demand

Table 3.5. Post-Embargo Energy Balance — 1980
(10^{13} Kilocalories)

ENTRY	OECD EUROPE	EEC (9)	GERMANY	DENMARK	NETHERLANDS	BELGIUM & LUXEMBOURG	ITALY	FRANCE	U.K. & IRELAND
COAL	249.0	207.2	91.0	7.1	2.4	12.0	12.9	28.2	53.6
OIL	803.8	660.4	155.4	16.3	41.1	36.4	118.5	128.0	164.7
GAS	265.4	248.6	55.9	---	54.2	16.1	31.8	32.9	57.7
HYDRO & NUC	214.9	114.9	32.7	---	2.9	5.5	20.4	26.7	26.7
TOTALS	1533.1	1231.1	335.0	23.4	100.6	70.0	183.6	215.8	302.7
COMMERCIAL-RESIDENTIAL	411.0	334.2	101.5	11.7	26.6	15.3	39.9	51.7	88.2
INDUSTRY	798.4	633.2	173.9	6.9	50.6	41.2	101.5	116.9	141.4
TRANSPORTATION	188.2	146.9	35.4	3.1	8.3	5.7	20.1	25.7	48.6
NON-ENERGY	93.1	79.4	19.8	0.9	1.4	4.8	14.4	17.3	17.9
BUNKERS	42.4	37.4	4.4	0.8	10.7	3.0	7.7	4.2	6.6
(ELECTRICITY)*	503.9	373.9	119.7	8.0	20.2	16.3	50.7	57.9	101.1

* Not to be included in totals

Table 3.6. Pre-Embargo Energy Balance — 1980
(10^{13} Kilocalories)

ENTRY	OECD EUROPE	EEC (9)	GERMANY	DENMARK	NETHERLANDS	BELGIUM & LUXEMBOURG	ITALY	FRANCE	U.K. & IRELAND
COAL	216.5	180.1	79.1	6.2	2.1	10.4	11.2	24.5	46.6
OIL	1114.9	916.0	215.5	22.6	57.0	50.5	164.4	177.6	228.4
GAS	221.2	207.2	46.6	---	45.2	13.4	26.5	27.4	48.1
HYDRO & NUC	214.9	114.9	32.7	---	2.9	5.5	20.4	26.7	26.7
TOTALS	1767.5	1418.2	373.9	28.8	107.2	79.8	222.5	256.2	349.8
COMMERCIAL-RESIDENTIAL	560.4	451.1	134.6	16.2	31.1	21.4	58.7	74.1	115.0
INDUSTRY	805.2	639.2	166.5	6.5	45.6	41.7	111.4	124.3	143.2
TRANSPORTATION	240.6	188.5	44.9	4.0	10.7	7.3	25.9	33.0	62.7
NON-ENERGY	102.5	87.5	21.8	1.0	4.9	5.3	15.8	19.0	19.7
BUNKERS	58.8	51.9	6.1	1.1	14.9	4.1	10.7	5.8	9.2
(ELECTRICITY)*	526.2	391.9	116.5	8.0	18.8	17.2	59.4	63.5	108.5

* Not to be included in totals

Table 3.7. Post-Embargo Energy Balance — 1985
(10^{13} Kilocalories)

ENTRY	OECD EUROPE	EEC (9)	GERMANY	DENMARK	NETHERLANDS	BELGIUM & LUXEMBOURG	ITALY	FRANCE	U.K. & IRELAND
COAL	277.4	220.7	99.7	11.8	2.8	12.2	14.9	27.0	52.3
OIL	1021.3	833.3	194.8	19.3	49.2	44.7	147.0	167.7	200.6
GAS	363.6	320.0	74.0	---	71.4	20.3	42.1	44.0	68.2
HYDRO & NUC	365.8	210.7	66.6	1.0	6.7	10.4	34.0	46.5	45.6
TOTALS	2028.1	1584.7	435.1	32.1	130.1	87.5	248.0	285.2	366.7
COMMERCIAL-RESIDENTIAL	543.1	428.0	132.3	15.7	34.1	18.9	54.8	67.2	105.9
INDUSTRY	1058.5	812.9	223.8	10.5	68.0	51.1	136.4	153.9	168.2
TRANSPORTATION	250.2	192.3	47.2	3.7	10.6	7.4	27.3	33.7	62.4
NON-ENERGY	128.5	110.1	27.1	1.3	6.2	6.7	20.9	25.7	22.3
BUNKERS	47.8	41.4	4.7	0.9	11.2	3.4	8.6	4.7	7.9
(ELECTRICITY)*	708.8	527.3	175.6	13.9	28.2	22.4	74.3	86.8	126.1

* Not to be included in totals

Table 3.8. Pre-Embargo Energy Balance — 1985
(10^{13} Kilocalories)

ENTRY	OECD EUROPE	EEC (9)	GERMANY	DENMARK	NETHERLANDS	BELGIUM & LUXEMBOURG	ITALY	FRANCE	U.K. & IRELAND
COAL	208.4	165.9	74.9	8.9	2.1	9.2	11.2	20.3	39.3
OIL	1399.0	1141.4	266.8	26.4	67.4	61.3	215.0	229.7	274.8
GAS	303.6	266.7	61.7	---	59.5	16.9	35.1	36.7	56.8
HYDRO & NUC	365.8	210.7	66.6	1.0	6.7	10.3	34.0	46.5	45.6
TOTALS	2276.8	1784.7	470.0	36.3	135.7	97.7	295.3	333.2	416.5
COMMERCIAL-RESIDENTIAL	721.7	564.1	168.7	20.2	39.7	26.0	78.9	94.1	136.5
INDUSTRY	1034.1	800.5	206.3	8.8	60.5	50.4	147.1	161.9	165.5
TRANSPORTATION	315.8	243.7	59.0	4.7	13.5	9.5	34.7	42.8	79.5
NON-ENERGY	139.7	119.7	29.5	1.4	6.7	7.2	22.8	27.9	24.2
BUNKERS	65.5	56.7	6.5	1.2	15.3	4.6	11.8	6.5	10.8
(ELECTRICITY)*	720.9	539.9	166.0	12.5	26.6	23.2	85.4	92.9	133.3

* Not to be included in totals

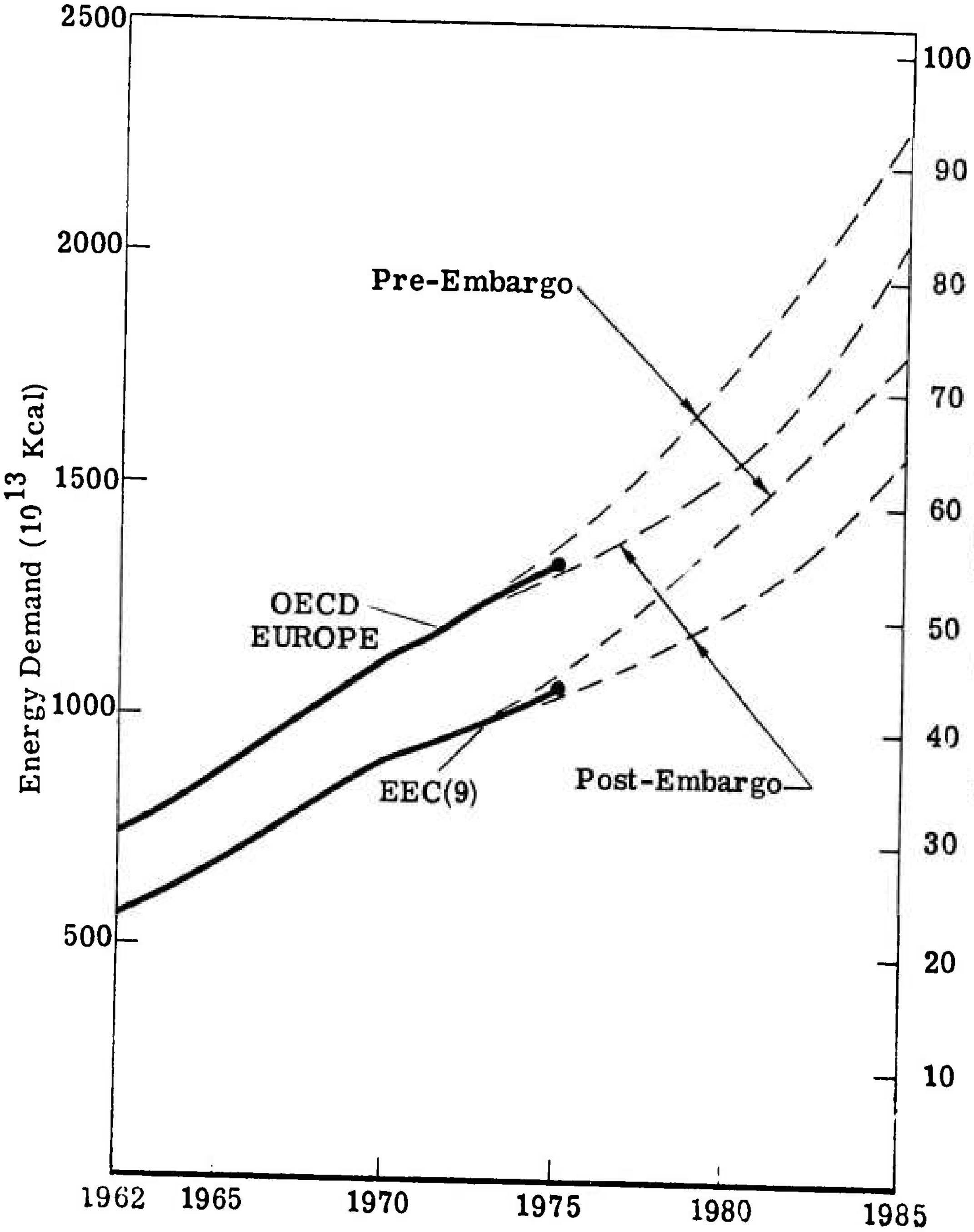


Figure 3.2. Projected Energy Demand of Western Europe

Table 3.9. Energy Demand Growth Rates
(Annual Percentage Increase)

PERIOD	OECD EUROPE		EEC(9)		JAPAN*	U.S. *
60-70	5.4		6.2		13.2	4.3
70-75	3.8		3.4		7.6	4.2
	PRE	POST	PRE	POST		
75-80	5.3	2.4	5.3	2.8	7.8	4.2
80-85	5.2	5.8	4.7	5.2	6.4	4.0

*Pre-Embargo Projections

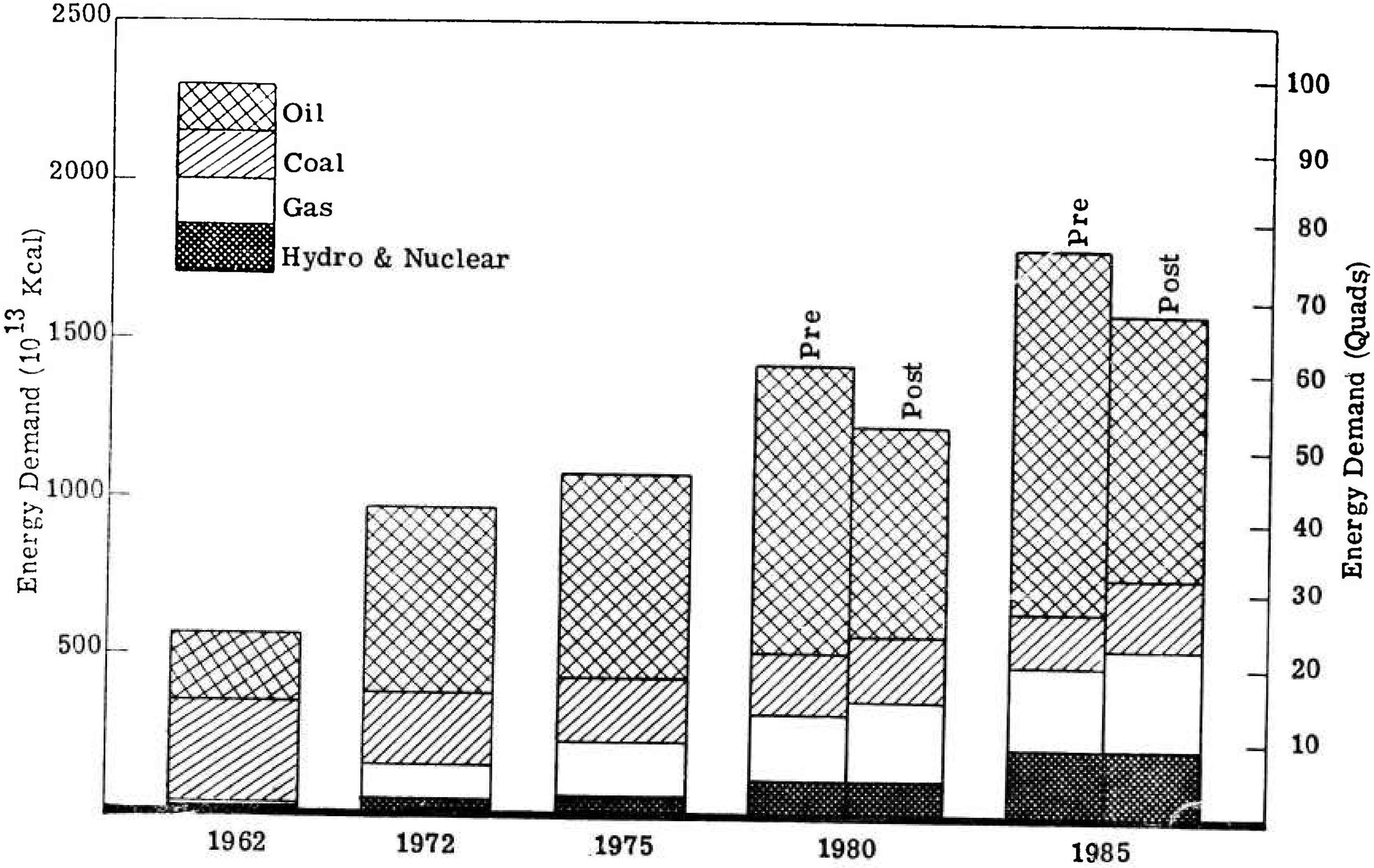


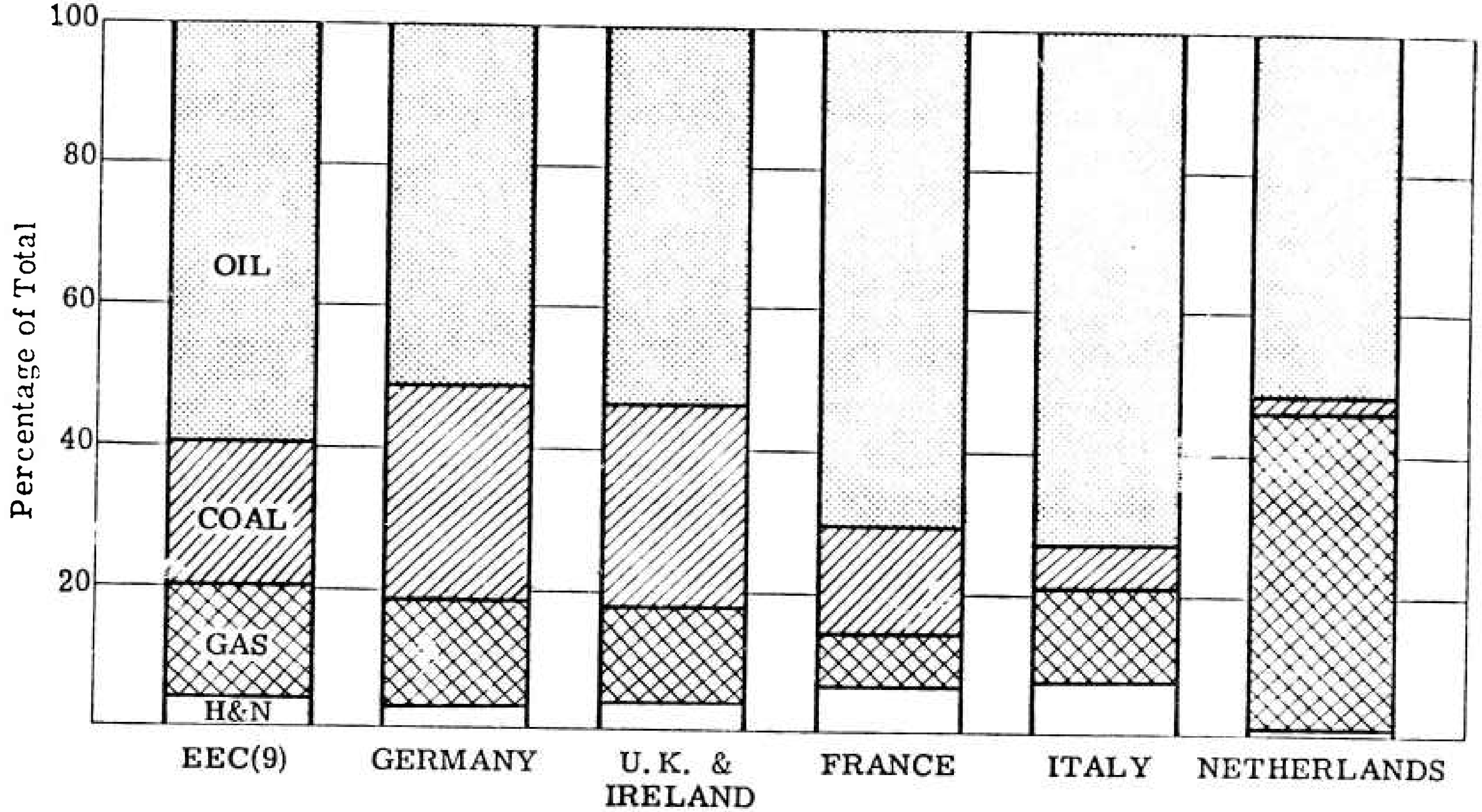
Figure 3.3 EEC(9) Fuel Requirements — Pre- and Post-Embargo

and from below by increased supply of coal and gas. The hydro-electric plus nuclear component is assumed not to change. The impact of variations in planned growth of nuclear power is discussed below.

The fuel splits have been expressed on a percentage basis by country for the 1975 and 1985 time periods (Figures 3.4 and 3.5). The almost complete dependence of France and Italy on oil is a significant feature of these charts. They gain some relief (on a percentage basis) by 1985 through significant planned increases in nuclear power. Germany and the U.K. (in 1975) are seen to have favorable positions in coal with respect to the rest of the community. The Netherlands is in a unique position with her abundant gas reserves — especially when one considers that as much as one-third of her oil requirements is for bunkers at Rotterdam.

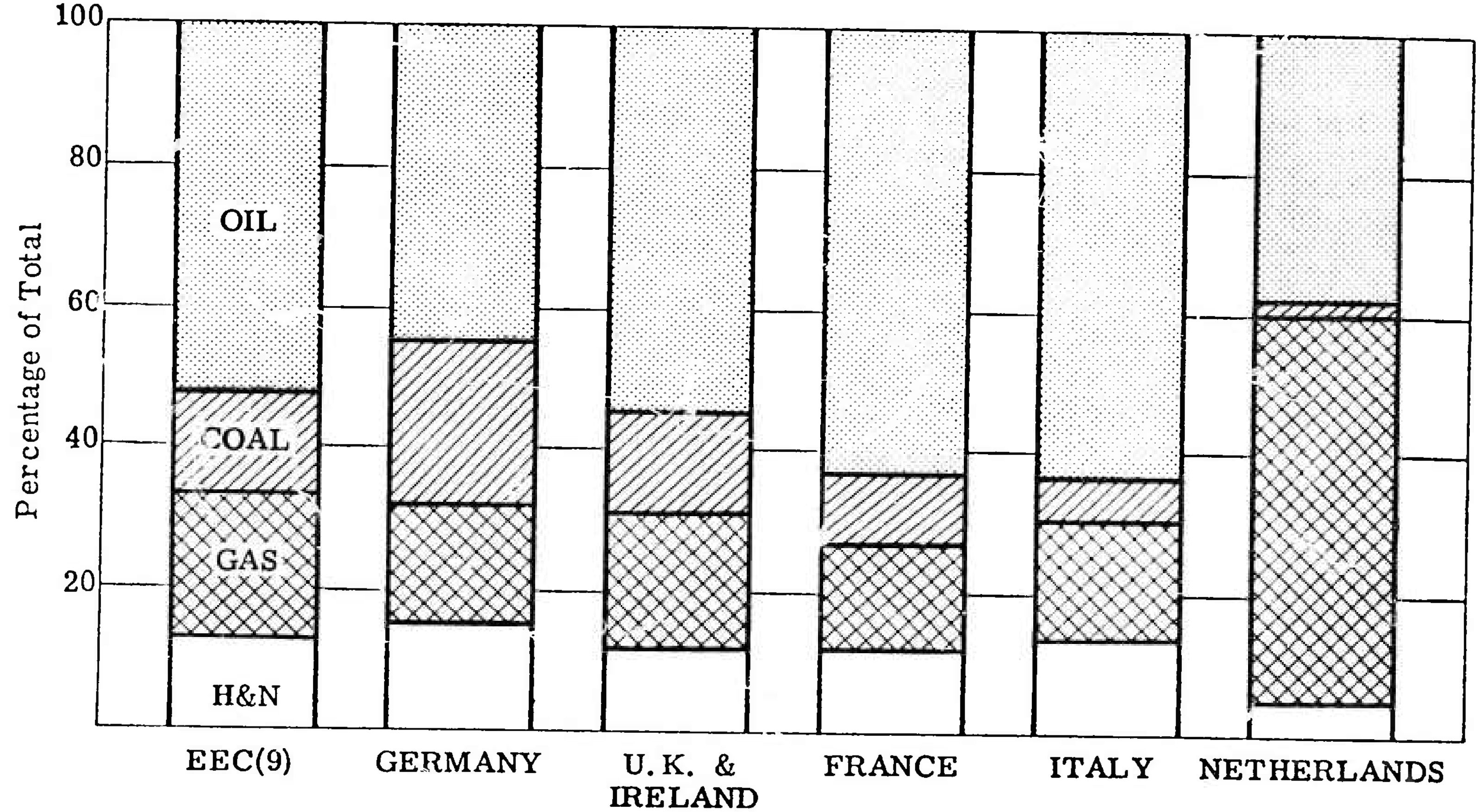
Alternatively, one can examine the energy demand split by consuming sectors. The composition of the EEC(9)'s demand by sector is given in Figure 3.6. Most of the increase in demand is coming from the industrial sector with a modest increase in commercial and residential. Transportation is seen to remain almost constant through 1985. Conversely, the data might be interpreted in terms of the impact of the oil price rise on the various sectors. Transportation is dominated by oil product consumption and is affected the most. Industry consumes large quantities of coal (particularly in the steel industry) and is affected the least. Figures 3.7 and 3.8 show the percentage splits by consuming sector for the EEC(9) countries for 1975 and 1985, respectively.

Electric power is an important constituent of the European community's energy situation — especially since many countries are



H&N — HYDRO AND NUCLEAR

Figure 3.4. Energy Split by Fuel — 1975



H&N — HYDRO AND NUCLEAR

Figure 3.5. Energy Split by Fuel — 1985 (Post-Embargo)

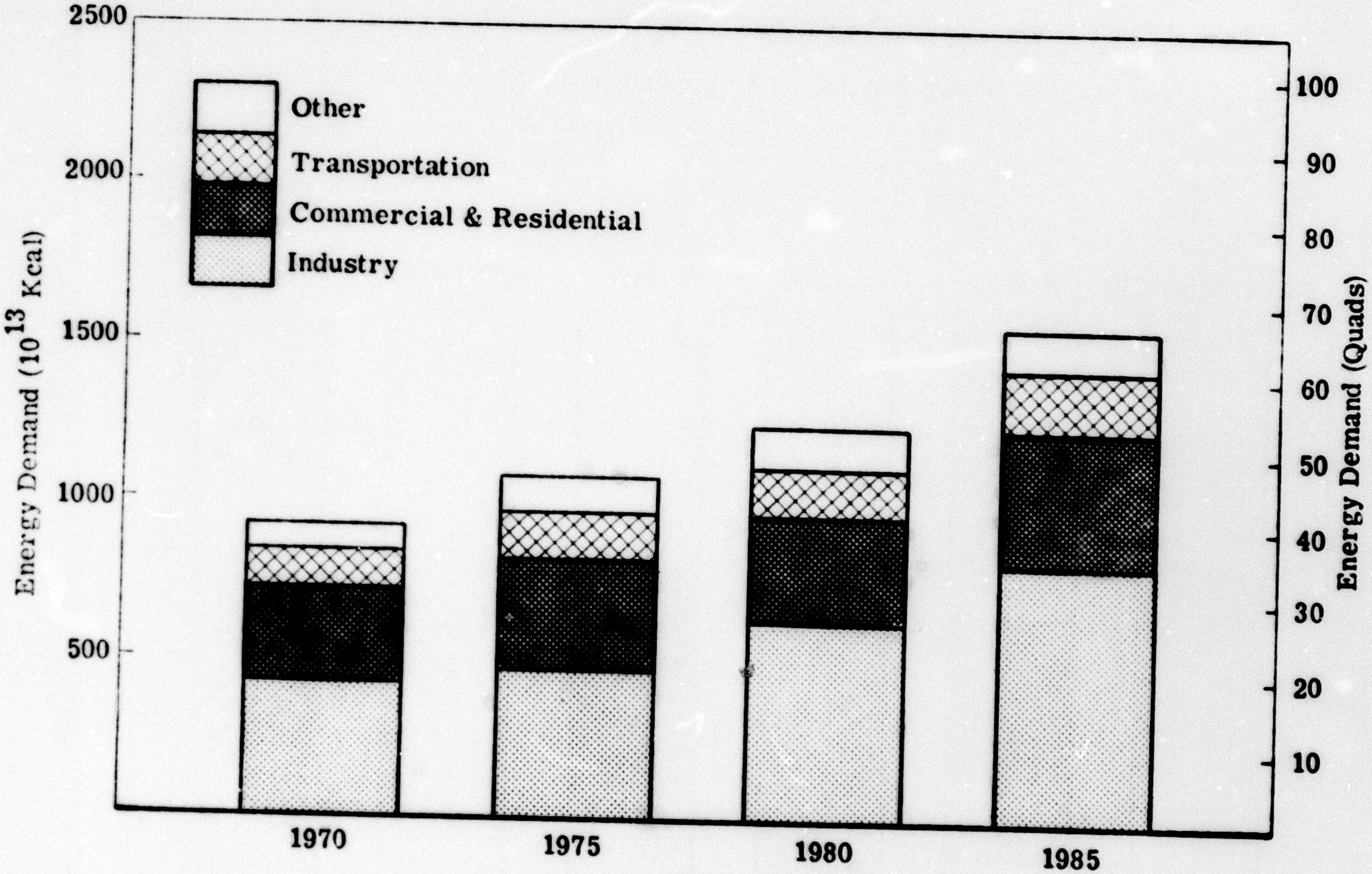


Figure 3.6. Energy Demand by Consuming Sector — EEC(9) (Post-Embargo)

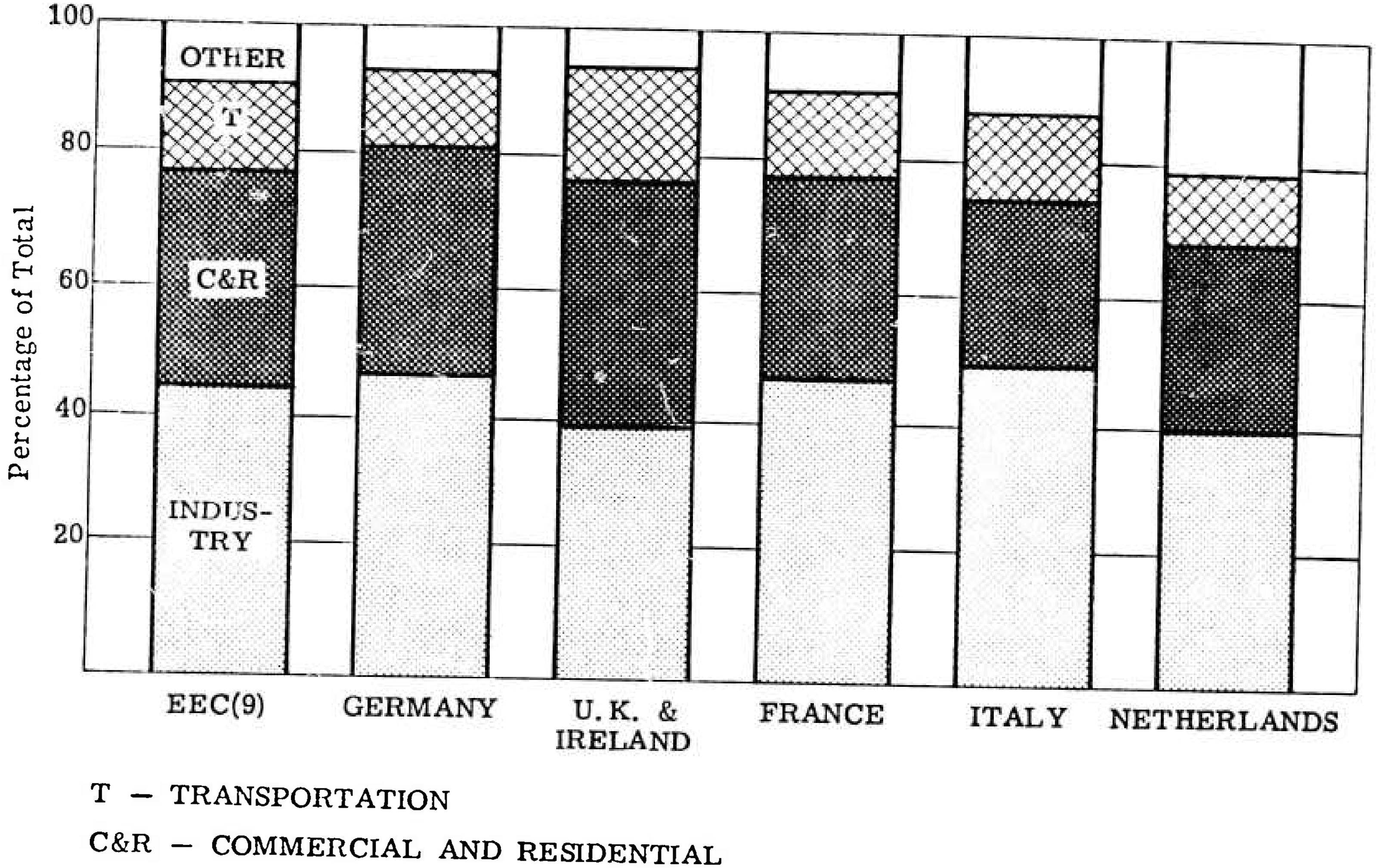
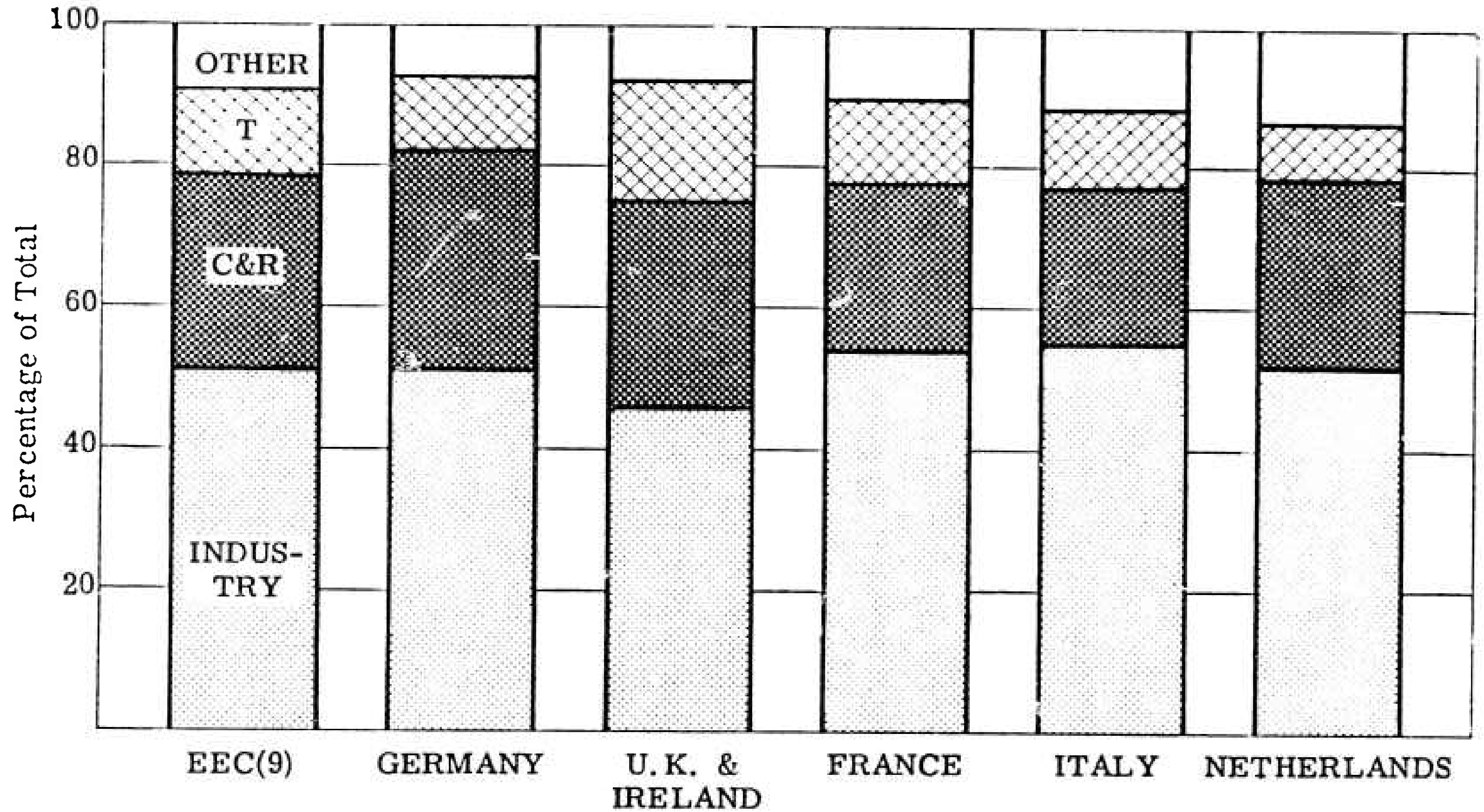


Figure 3.7. Energy Split by Consuming Sector — 1975



T – TRANSPORTATION

C&R – COMMERCIAL AND RESIDENTIAL

Figure 3.8. Energy Split by Consuming Sector – 1985 (Post-Embargo)

relying on a large increase in nuclear power to meet increased electricity demand. Figure 3.9 shows the percentage of total energy demand represented by electricity for OECD Europe, the EEC(9), Germany, France, and the U.K. The demand is expressed in millions of metric tons of oil equivalent (1 MTOE = 10^{13} kcal), and represents pre-embargo projections. Figure 3.10 shows the contribution of the various fuels to the EEC's total electricity demand for 1980 and 1985 for three scenarios. The first case shows the fuel split for the pre-embargo projection. The estimates of the hydroelectric plus nuclear contribution are those of the EEC. The second case reflects the decrease in demand and shift from oil to coal and gas generated by the post-embargo oil price increase, while holding the planned hydroelectric plus nuclear component constant. The third case reflects estimates by the U.S. Atomic Energy Commission*[15] of worldwide nuclear power plant installations. Since the AEC itself has traditionally overestimated growth in nuclear generating capacity, it is reasonable to expect that the situation in Europe will see less nuclear generating capacity than planned. The shortfall in nuclear capacity was converted to additional oil requirements as shown. The net effect is that the savings in oil for electricity over pre-embargo requirements may be only marginal. Figure 3.11 depicts the same scenarios for four countries – Germany, Italy, France, and the U.K. Germany's post-embargo electricity production is actually seen to rise, due to the large contribution of coal and gas relative to oil in the pre-embargo mix.

The important question, of course, is not what the energy demand will be, but how will it be met? What domestic resources will be available and how dependent will Western Europe be on OPEC

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* Now the Nuclear Regulatory Commission (NRC)

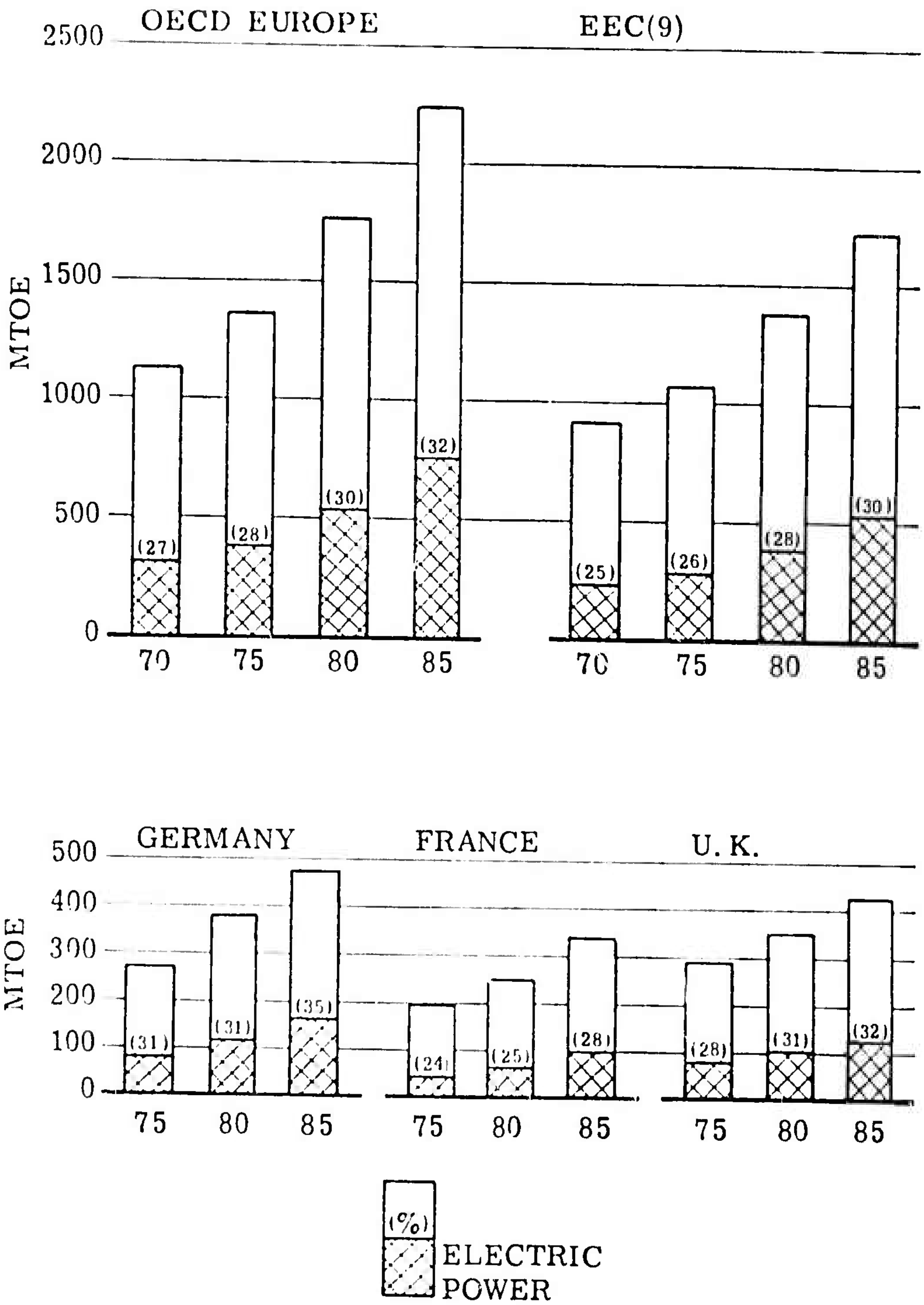

Figure 3.9. Electricity – Percentage of Total Energy Demand (Pre-Embargo)

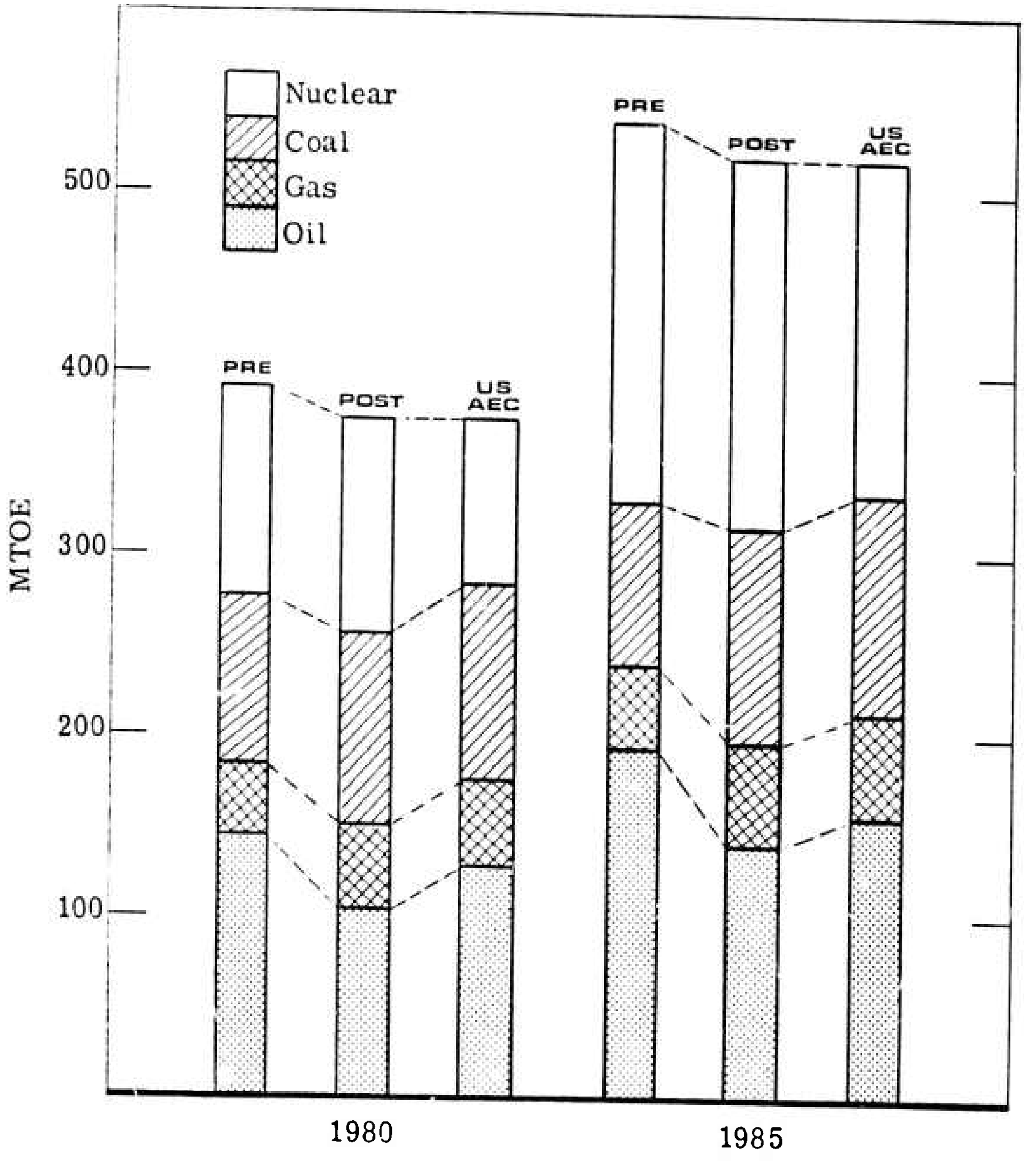

Figure 3.10. EEC(9) Electric Power Fuel Mix for Three Cases

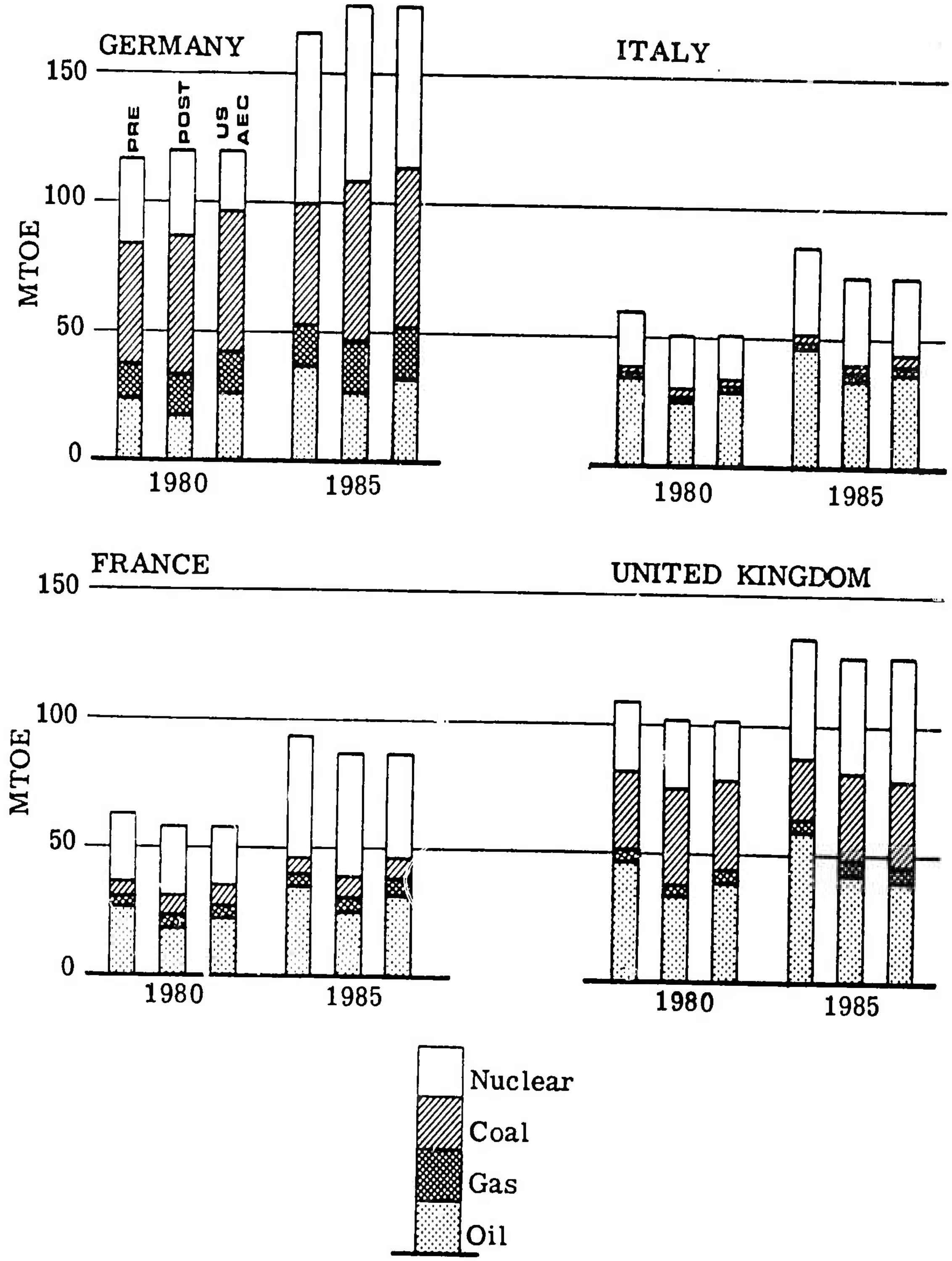

Figure 3.11. Electric Power Fuel Mix for Four Countries

oil? Table 3.10 summarizes very simply the analysis of Section 2 and Appendix A. Based on the demand projections of Tables 3.5 and 3.7, and the resource summary of Table 2.5, it shows how close the various countries are expected to come to meeting forecast demand from domestic supply and already identified non-OPEC imports. In 1980 a marginal surplus in coal and a 23 percent deficit in gas are projected for the EEC(9). In 1985 there is still a marginal surplus of coal, but the gas deficit has grown to almost 40 percent of demand, as the Netherlands' production will be only marginally greater than demand. The U.K. is the only EEC country with any oil production to speak of, and her's is expected to account for only 15 percent of her own requirements. The coal surplus for the U.K. is in comparison to what was anticipated prior to the embargo and is achieved by merely maintaining current production levels. This "surplus" will, in all probability, be absorbed internally.

These numbers can be translated into energy impact requirements which will have to be met by some combination of OPEC and currently unidentified non-OPEC sources. Figure 3.12 shows the requirement of the EEC(9) in 1980 and 1985 for such imports which represent in excess of 50 percent of total energy demand. Excluded from the gas component, for example, are existing contracts of France and Italy for Algerian gas and LNG. As was discussed in Section 2, there are prospects that this requirement may be met in part by the North Sea and by imports from the Soviet Union and Eastern Bloc countries; nevertheless, the dependence on OPEC resources will be significant for some time to come.

One of the most important consequences of the oil price rise has been its impact on the balance of payments of the oil importing

Table 3.10. Domestic Fuel Production Compared to Projected Requirements

COUNTRY	FUEL PRODUCTION RATIOS			
	COAL		GAS	
	1980	1985	1980	1985
EEC(9)	+δ	+δ	-	-
GERMANY	EVEN	-δ	-	--
U.K. & IRELAND*	++	++	-	-
FRANCE	-δ	-δ	--	--
ITALY	-	-	-	--
NETHERLANDS	-δ	-δ	+	+δ
BELGIUM & LUX.	-	-	-	-
DENMARK	--	--	**	**

δ = ±10%

+, - = >10% to <50%

++, -- = >50%

*U.K. Oil: 15% in 1980 & 1985

**Denmark Projects no Gas Usage

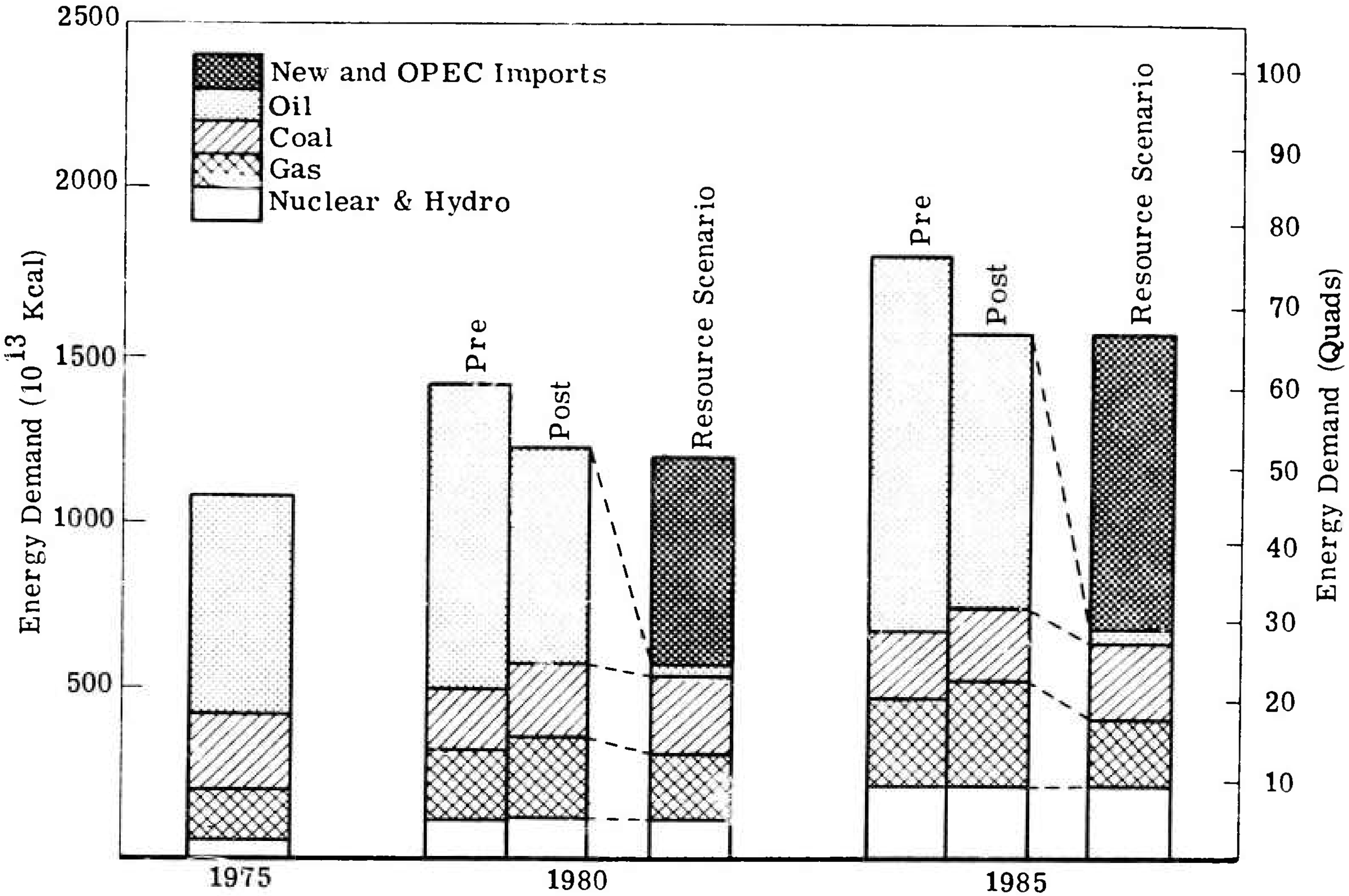

Figure 3.12. Projected Non-OPEC Resources for Meeting EEC(9) Energy Demand

countries. Table 3.11 presents the dollar outflow associated with oil imports of the EEC and its member countries. The net effect of the price rise (assuming an equivalent price of oil of $9/bbl) and demand reduction is to double the dollar outflow. The impact of this large increase in imports and the alternative uses of petrodollars by OPEC is discussed in Section 4.1.

Table 3.11. Cost of Oil Imports

COUNTRY	DOLLAR OUTFLOW ($\$10^9$)			
	1980		1985	
	PRE*	POST†	PRE*	POST†
EEC(9)	18.7	39.8	23.4	50.7
GERMANY	4.5	9.6	5.6	12.2
U.K. & IRELAND	4.3	8.9	5.2	10.8
FRANCE	3.7	8.1	4.9	10.6
ITALY	3.5	7.5	4.5	10.0
NETHERLANDS	1.2	2.5	1.4	3.1
BELGIUM & LUX.	1.0	2.2	1.3	2.8
DENMARK	.5	1.0	.5	1.2

* $3/bbl OIL

† $9/bbl OIL

Section 4

IMPLICATIONS OF WESTERN EUROPE'S ENERGY SUPPLY AND DEMAND

4.1 ECONOMIC IMPLICATIONS

It is clear from the analysis, the energy demand projections, and the projections of how this demand will be met, that over the next ten years a major portion of Western Europe's energy will come from oil imported from the Persian Gulf. This will be true even assuming a reasonable rate of development of North Sea production. Two situations in particular require analysis. The first is what would be the effect of an oil embargo; the second is what will be the effect of a sustained supply of oil at the current high prices. The answer to the first question is straightforward and relatively simple. A sustained and effective oil embargo by OPEC of Western Europe would have a severe impact on its economy. There does not appear, in the next ten years, to be any economically viable way of achieving anything close to energy self-sufficiency. Measures to reduce the impact of a temporary embargo such as storage and emergency conservation and allocation plans could be implemented, but the basic fact remains that an oil embargo of long duration would be a serious economic threat to Western Europe.

The more difficult question to answer is what will be the effect on the economies of Western Europe of continued availability of Persian Gulf oil but at the current high prices. As was pointed

out in Section 3, the one study, by Hudson and Jorgenson, which addresses this problem suggests that a fully-employed industrialized economy has enough potential substitutes for energy and conserving energy that a cutback in energy use associated with today's higher energy costs would not have a large impact on the level or rate of growth of GNP. They state:

> The basic properties of the model are illustrated by the result that, in the 1980 simulations for example, energy input can be reduced by 8 percent at the cost of only a 1 percent increase in average prices and a 0.4 percent decrease in real income. In other words, the flexibility of the economy in adapting to changing resource availabilities, and the power of the price system in securing this adaptation, mean that substantial reductions in energy use can be achieved without major economic cost.(10)

However, even if this is true, it is important to note that if energy prices become high enough and the reduction in energy use were great enough, the impact could be significant. If the OPEC cartel were to set a price of $1000/bbl for crude oil, this would be virtually equivalent to an embargo and it would produce serious economic effects. This brings to light that recent statements by some oil exporting countries that they will not withhold oil supplies in the future are largely meaningless, even if true, unless they specify a price or price range at which they will sell oil. Therefore, while the threat of an embargo remains a real concern, the question of the future price of oil from the Persian Gulf is perhaps an even more important concern.

For the present discussion, however, let us suppose for the moment that there will be no future oil embargo and that the price of crude at the Persian Gulf will remain relatively stable at the current level. Some fundamental questions still remain. Will Western

European economies be destroyed? Will economic growth come to a halt? Will Western Europe go broke? Will it be bought out by Arab oil producers? All these questions have been asked seriously in the press and by public officials and require careful analysis both because of their seriousness and because of plethora of wild assertions that have been made about bad things to come.

For the purpose of discussion, let us suppose that the economies of Western Europe adjust to higher energy prices and continue at near full employment, but use less energy than before because of the higher price of imported crude. Will there be a drastic drop in GNP or will the rate of growth of GNP be significantly less? It seems likely that the answer to both questions is no, based in part on the work by Hudson and Jorgenson and in part by common sense considerations. For example, even with higher oil prices, the use of energy is projected to be only about 10 percent less than at pre-embargo prices and the growth rate of energy use will be about the same. If there were no possibilities for energy conservation and energy substitution (i.e., if energy were a fixed proportion of GNP regardless of price), then there would be an initial decrease in GNP of about 10 percent followed by a rate of growth roughly as before. We know there are many possibilities for substitution and conservation from both engineering studies of particular production processes and from econometric studies such as the one by Hudson and Jorgenson. Therefore, at worst one would expect a 10 percent initial drop in the GNP of Western European economies followed by continued growth at rates roughly comparable to the past. Obviously, the effect of higher prices, assuming that economies adjust to the change in relative prices and remain fully employed, will be much smaller than a 10 percent decrease in GNP.

If this is in fact the case, it is comforting as it appears that energy prices based on $3/bbl oil are not likely to return. Even when the oil from the North Sea is brought in, our cost estimates show that its cost will be well above the old price of $3/bbl. While it will reduce the threat of an embargo or further price rises, it will not return energy costs to pre-embargo levels. Further, alternative sources of energy and their associated technologies (nuclear, oil shale, etc.) do not appear to offer a low cost alternative.

What then is the threat, if any? It appears that the potential problems are ones associated with short term adjustment within countries and in international monetary markets. The immediate impact of higher oil prices will be to cause oil importing countries to have significant balance of payments deficits in the short run and there is likely to be economic dislocation among industries where petroleum products are a major input (e.g., petrochemicals), and among low income groups that consume a significant amount of energy (e.g., consumers in cold climates whose space heat bills quadruple). If, in response to short balance of payments deficits, the threat of a future embargo, and short term economic dislocation, governments adopt restrictive and protectionist economic policies, particularly policy directly aimed at reducing oil imports, current economic conditions could worsen significantly. It is the possibility of a serious recession triggered by policies in response to short term problems resulting from the increase in the price of oil that appears to us to be the greatest threat to Europe's economic health and stability.

As a case in point, consider our own economic policy. At a time when the economy is significantly underemployed, the President is proposing that we cut foreign oil imports by 1,000,000 bbl/day

as a move toward energy self-sufficiency. This cut is to be achieved by a tariff on imported oil which will result in higher prices for petroleum products and reduce use. What we are voluntarily proposing to do to ourselves is just what we fear OPEC might do to us by an embargo. Further, at the same time that we are implementing this policy to restrict the importation of oil and raise the price of petroleum products, we are continuing to regulate the price of natural gas, keeping it well below market clearing levels, thereby removing the price incentive for users to undertake substitution for and conservation of this scarce energy resource. Under such policies the price system will not secure the appropriate adaption that is the key to the findings by Hudson and Jorgenson. Such policies, which may have extremely deleterious economic effects, are widely and seriously discussed and in some cases being implemented.

Is the balance of payments deficit that oil producing countries are experiencing likely to be a long term problem? To answer this question it is useful to ask, what will the oil exporting countries do with the currencies that they receive? There are four possible options. They can:

1. Bury them in the sand;

2. Put them into short term liquid assets and bank accounts;

3. Increase consumption and investment at home; or

4. Make investments abroad.

From the point of view of the oil importing countries, alternative (1) would be equivalent to having oil as gift, although there would always be some nervousness about what would happen if the money were to be removed from the sand and suddenly used to purchase goods and

services. While this could have significant inflationary effects in the countries whose currencies had been hoarded, it would certainly generate a surplus balance of payments. We will return subsequently to this problem.

The second possibility is that the oil exporters would put their receipts in the currencies of Western Europe into short term liquid assets or bank accounts. This is in fact what has been happening over the past year. This in itself creates no difficulty except when a particular holder of these assets decides to switch huge amounts of money from one institution to another or from one currency to another. Even a major bank which has several billion in deposits withdrawn on short notice might experience serious short term problems of adjustment. Further, large scale movements from one currency to another might cause highly disruptive changes in the value of one currency vis a vis others. For example, if a major holder of Western European currency suddenly starts to sell large amounts of one currency and to buy another, the currency being dumped will drop in value vis a vis other currencies and as a result the imports of the country whose currency is being dumped will become very expensive and its exports very cheap. This can cause sudden shifts in supply and demand, with results such as domestic shortages and high domestic prices for certain exports, as well as high prices for imports. While severe currency fluctuations of this type are basically short run phenomenon, they:

1. Can cause serious disruption of a country's economy; and

2. May set up expectations and a dynamic situation which will exacerbate the problem and create serious longer term problems.

Suppose in response to a sudden drop in the value of a currency, other holders of that currency, fearing a further decline, decide to sell. This will push down the value of a currency still further. Governments faced with a falling currency may try to stem a flow of capital by undertaking restrictive monetary policies and setting high rates of interest which, while stemming the flow of capital, may also depress economic activity and employment. Even the country whose currency is being sought may experience significant problems. As the value of a country's currency increases, its exports become less competitive abroad. A sudden shift upward in the value of currency may have very damaging effects on its export industry. It is widely claimed that the recent rise of Swiss franc is attributable to purchases by oil producing countries. This problem is viewed with some alarm by the Swiss government which has taken strong steps to stem inflow of foreign capital.

The third alternative is for the oil exporting countries to increase investment and consumption at home. In this case, the currencies would be spent on goods produced in the developed countries and, as a result, the balance of payments would be redressed. However, it appears that the oil exporting countries will have a surplus of foreign currencies in excess of their consumption needs and their ability to absorb investment.

The fourth alternative is to invest abroad. Direct investment in assets in the industrialized countries would directly redress the balance of payments through international capital movements. Money invested in the less developed countries would be spent on capital goods which would, in turn, be purchased from the industrialized world, thus correcting the balance of payments problem. Wherever the oil producing countries invest their holdings of foreign

currencies, these currencies will ultimately be used to purchase assets or goods in the country of that currency.

The real problems created by the current flow of money from the oil importing countries to the exporting countries are associated with the difficulty of short term adjustment to balance of payments deficits, to sudden shifts of significant sums from one financial institution to another or from one currency to another. Further, if a country's currency has been hoarded, while this is desirable in the sense that it has traded paper for oil, there is always the threat that the holder of this paper will suddenly decide to use his hoard to purchase goods and services or to switch to another currency, causing short term economic disruption. The key to eliminating these difficulties is to develop international measures to mitigate these short term fluctuations and the effects of these fluctuations.

There is a strong reason why it is not in the interest of the oil exporting nations to continue to keep their surplus earnings in low interest bank accounts or to hoard them. With high rates of inflation, the real value of these holds are being deflated in many cases by 15 to 20 percent per year. Even for wealthy countries and individuals, this is bound to be significant. In addition, as the Arab countries become more sophisticated and buy more technical advice, they are more likely to undertake developing a balanced portfolio of assets including investments in Western Europe and the United States.

There are two strategies they can follow with regard to such investments. They can buy highly diversified portfolios and be passive stockholders without control of any customer, or they can buy a major interest in a smaller number of companies. This latter strategy, which Arab investors now appear to prefer, has the advantage that it

gives them a voice in the management, but the disadvantage that it may create anxiety and animosity in the countries where they invest, and it makes them vulnerable to control and expropriation.

There has been talk that the Arabs will take over the assets of the industrialized countries. If one looks at the real wealth of OECD countries, one finds that the surplus oil revenues are only a tiny fraction of this wealth. At the same time, these surpluses are sufficiently large to buy a controlling interest in many major companies. Except for public fears about foreign domination, this presents no significant problem as long as the firms are managed in an efficient, businesslike, competitive manner. However, if such control were exercised irresponsibly or for political purposes contrary to the national interests of the host country, the controlling foreign interest would be subject to control, taxation, or expropriation. The vulnerability of Western Oil Companies is a case in point. Therefore, the control and domination of production in Western Europe and the United States does not appear to be a real problem in the sense that the national security of the U.S. and countries in Western Europe would be threatened by Arab domination of industry, resulting in irresponsible and irrational industrial decisions.

A more serious prospect than having an Arab controlled firm shut down in an attempt to win political concessions or mismanaged in order to weaken a Western European economy is the prospect of using Arab political influence in Western Europe. The oil exporters could become important members of the industrial establishment by buying into European firms and could have significant influence on the internal politics of the countries where they owned assets. But even if Arab countries do not obtain major interests in Western Europe they are still

likely to achieve much greater influence from the mere fact that they represent a large potential market for Western European goods and services. Countries competing for this business must be sensitive and responsive to Arab views and interests. Whether it is governments seeking to reduce the cost of developing and maintaining weapons systems by supplying Arab countries and thereby increasing overall production or construction firms competing for Arab contracts, the concern for these enterprises will be translated into political forces favorable to Arab views and interests. The implications of this phenomenum for U.S. relations with Europe are not altogether clear; however, it appears that this competition for Arab markets as well as for capital and oil is likely to be the source of increased conflicts of interest among the industrialized countries unless a crisis situation materializes which forces them to develop a unified strategy for dealing with OPEC.

To summarize, the major problems arising from the present energy situation are associated with sudden large scale movements of money held as surplus revenues. The remedies are international policies to solve short term adjustment problems and to mitigate short term effects. The long term effects of current energy costs are likely to be minimal and the transfer of wealth from the oil importing countries to the exporting ones will not result in the Arabs buying out Europe or controlling its economy. The threat of an embargo remains real, but will diminish as North Sea oil comes on line. The latter will also reduce the balance of payments problems of Western Europe. The real problem is coping with short term problems of adjustment that, if mismanaged, could cause long run problems. Finally, whether through increased representation in Europe through industrial ownership or through competition for Arab markets and

capital, the political influence of the oil exporting countries in Western Europe can be expected to increase significantly. The implications of this are part of an important area that needs further study.

4.2 GEOPOLITICAL IMPLICATIONS OF EUROPEAN ENERGY RESOURCE DEVELOPMENTS

4.2.1 Background

Earlier sections of this report and Appendix A inferentially discuss the geopolitical ramifications of the development of European energy sources, primarily Gronigen natural gas and the ongoing development of the North Sea. The implications of joint development efforts and trans-European pipelines, the rise in the significance of the Netherlands, and the economic problems of the U.K. — all of these factors have local, regional, and in some cases, global significance. Certainly, success in current efforts to establish a "buyer's cartel" as a countermove to OPEC would complement European energy resource development plans and strategies by the various countries of the EEC to secure either indigenous or non-OPEC sources of energy. This section will not address the day-by-day interactions between the various countries as various concepts to counter almost complete dependence on OPEC are addressed, but will concentrate on the two most significant geopolitical factors. These are: the immense significance of the energy resources of the North Sea; and the rise of the Eastern Bloc and specifically the U.S.S.R. as a potential and viable source of non-OPEC oil and gas for Western Europe.

4.2.2 The Significance of the North Sea Energy Sources

Development of the resources of the North Sea has been both a unifying and devisive force in the geopolitics of Europe. As a unifying source, it has contributed to the construction of a massive complex of inter-European pipelines in which oil and gas, the bulk of which originates in the Netherlands (including OPEC oil through Rotterdam/Europort), are transmitted all the way to central Italy. Frontiers are moot in such a network; contracts are executed between supplier (which in itself may be a multinational consortium) and the consuming nation (typically a national oil company, or the local component of a multinational firm). In the development and distribution of North Sea oil and gas, the Common Market is truly "common." Philipps, an American concern, spearheaded the development of Ekofisk in Norwegian waters and is piping natural gas to Emden, West Germany, for distribution through the Gronigen (Netherlands) pipeline complex throughout Western Europe. Oil, from Ekofisk, on the other hand, flows through a pipeline to the U.K. The U.S., the U.K., and a large group of state-owned oil companies have worked cooperatively and well in the communal development of the North Sea.

However, on a country-by-country basis, development of the North Sea has caused friction. Countries of the continent, heavily dependent on OPEC oil, are unhappy with the pace of development of reserves in the Norwegian sector. Norway, with a population of only 4 million, wishes a staged, gradual development of her energy resources, with maximum government participation (Statoil or Norsk Hydro) and limited leasing. In short, the area is to be developed commensurate with the capacity of the Norwegian economy to absorb the income. Norway is also talking of $9/bbl oil and possibly higher,

bringing the price close to that asked by OPEC. Norway has proposed a 90 percent tax on foreign consortia who are developing the fields, and, not unexpectedly, some have withdrawn. Norway can thus point to the lack of private-sector activity in the development which takes some of the onus of holding back development from governmental shoulders.

The Norwegian policy irritates those countries who are paying in the $12/bbl range for OPEC oil. Norway's logical rejoinders are twofold. Do not use up the oil faster than necessary, the reserves are not renewable; and do not acquire funds from oil sales faster than the economy can absorb them. Both parties are essentially "right" but friction is present. Norway has publically stated that she may consider membership in OPEC — whether this was a political ploy or not remains to be seen. If Norway's prices approach those of OPEC, the difference will be moot. In the meanwhile, Norway is under internal pressure to accelerate North Sea development and devote funds to lower domestic taxes, social services, and assistance for the relatively impoverished northern provinces who traditionally have been neglected by the Oslo government and exist on a marginal economy of fishing and lumbering.

4.2.3 The Emergence of the U.S.S.R. as a Major Energy Supplier to the EEC

In a quiet and unobtrusive fashion, the U.S.S.R. passed the United States as the world's largest producer of oil, in the fall of 1974. The overall production on a national basis was up 7 percent from 1973, while production in the U.S. fell 3 percent. Massive development of Siberian fields, and the construction of new pipelines is only one factor; need for foreign capital to make purchases from

the West is another and possibly dominating factor. The U.S.S.R. has already signed a 20-year oil import agreement with France; supplies France, Italy, and West Germany with natural gas; and added $393 million to her foreign exchange surplus in 1973 from oil and gas sales to the West. Reserves are adequate for such an export program, and Eastern Bloc nations do not have the industrial base to absorb energy in such quantities. The U.S.S.R. itself has ample domestic energy supplies and is expanding industry at a rate such that there will remain adequate oil and gas reserves for export. Western Europe (and Japan) are a ready and eager market for such sources. By the end of 1974 the U.S.S.R. had accomplished the following:

- Was well under way in the construction of a natural gas pipeline to Italy.
- Had completed one natural gas pipeline to West Germany and was embarked on the construction of a second,
- Had engaged in a unique trilateral trade agreement with Iran and West Germany by which Iranian gas was piped to the U.S.S.R., and U.S.S.R. gas, in the same quantity, was piped to West Germany. West Germany pays Iran directly for the gas, including a "transportation service charge" by the U.S.S.R.

The U.S.S.R. and Poland have emerged as major exporters of coal to Western Europe. With the closing out of many coal mines (see Appendix A), the dependence of Western Europe on imported coal (U.S., Australia, Canada) is increasing. Poland has become a major supplier of coal, and the U.S.S.R. is increasing shipments.

Thus with the U.S.S.R. emerging as a major supplier of oil and gas, and a minor supplier of coal to Western Europe, another alternative source of these energy resources appears. Its viability

in times of global crisis is questionable. Whether the U.S.S.R. would support an OPEC embargo is unknown. It does offer Europe, however, economic and political options that should be carefully considered, particularly in the global petroleum economic policies of the United States.

4.2.4 Additional Geopolitical Factors

The following are areas of potential conflict, impact, or problems that have arisen as Europe develops not only North Sea, but offshore energy resources.

Doctrine of the Continental Shelf

International Seabed conferences continue "to agree to disagree" in innumerable discussions of this highly complex subject. The Median Line concept was applied to the North Sea before the extent and more importantly the distribution of its energy resources were known. Denmark and West Germany were "shortchanged" in this agreement and have expressed unhappiness as to the contents of their respective sectors. More seriously, oil reconnaissance in the Aegean Sea has exacerbated an already serious political strain between Greece and Turkey over sovereignty of the Aegean Islands and (possibly) the oil that lies in Aegean waters. Explorations off Corsica, Sardinia, and elsewhere are potential areas of problem.

The Expiration of Intra-Community Fuel Exports

There is a situation which has yet to arise but which is easy to predict on the basis of the data of the previous sections. Germany is currently a major supplier of coal to the other countries of the

European community. Similarly, the Netherlands is a major supplier of gas. However, examination of the energy demand projections for these two countries shows that during the 1980-85 timeframe, local demand will exhaust domestic supplies and there will be no surplus available for export to member countries of the EEC(9). At a minimum, strained relationships can be expected as two countries prosper and maintain a measure of energy independence while their neighbors see historical sources cut off in the face of increasing difficulty to satisfy demand. More seriously, the community may fracture as each country imposes more and more nationalistic trade restrictions and competes openly for energy supplies.

4.2.5 Summary

The geopolitical ramifications of Europe's demand for oil and gas, and the competition for supplies from OPEC, the North Sea, the U.S.S.R., and new and as yet undeveloped areas are limited only by the imagination of the scenario writer. The previous section contained highlights of only a few of the developments that have occurred in the immediate past, are currently occurring, or are likely in the immediate future.

4.3 TECHNOLOGY TRANSFER

4.3.1 General

Technology transfer from the United States to Western Europe may be divided into two potential phases, short term and long term. Short term technology transfer offers little opportunities. Several U.S. R&D programs are being paralleled in Europe (e.g., automated longwall mining). Others (e.g., coal gasification and

liquefaction) originated in Europe, were abandoned, and are now being developed in the U.S., based on pre-World War II technologies based on wartime necessities. While Europe tracks the development of new approaches to these programs, little short term technology transfer is foreseen. Long term developments, as these technologies are refined, may well be amenable to transfer and exchange.

4.3.2 Short Term

Major short-term technology transfer opportunities are in the oil and gas area. They are already occurring, not on a government to government basis, but through the multinational oil companies. Thus enhanced (secondary and tertiary recovery systems) already in widespread use in the United States may be applied wherever a multinational company or affiliate is operating. Thus far, low-producing European inland oil fields have not been subjected to enhanced recovery techniques because of costs, and because investment in North Sea oil and gas seems a more promising investment. Still, particularly in such areas as fireflood, chemical stimulation of reservoirs, and other advanced technology enhancement technologies, the U.S. clearly has the technical edge.

A few years ago, it seemed that the U.S. had the technical advantage in design and operation of offshore oil rigs and platforms. However, Gulf of Mexico designs were not suited for the North Sea, and France (the Pentagone Series), Japan, and especially Norway, with its immensely successful Aker H-3 rigs, have taken the technical lead. (Figure 2.5 portrays an Aker H-3, 25 of which are currently on order.

World leadership in geophysical techniques for oil and gas exploration remains with the U.S., but technology transfer is an

ongoing process as U. S. multinational firms are active worldwide. The U. S. likewise has a technical edge in deep and undersea drilling technology, and worldwide firms share this expertise and background.

4.3.3 Long Term

There are several areas of resource development in which U. S. programs currently under development would have considerable implications in the context of Europe's energy requirements. Foremost among these are the various programs in high and low BTU coal gasification and advanced tertiary recovery methods of oil.

Enhanced Recovery Systems

The U. S. oil producing industry has adopted this term, having found, for example, that "enhanced recovery" is a more accurate term than "secondary and tertiary" since the latter terms imply a sequential process. More and more U. S. oil development firms will proceed directly to what may be termed "tertiary recovery" systems such as fireflood, steam-injection, or chemical processes. It may well be that the smaller fields on inland Europe may be amenable to enhanced recovery techniques from the start, and that production supplemental to the North Sea from numerous small fields in Inland Europe will be feasible.

Various Coal Conversion Processes

Based on wartime requirements for fuel and very limited access to oil, numerous processes, primarily German, were instituted in the 1940s to provide wider uses of domestic coal. With the end of the War, and the rebuilding of Europe's industrial plant on a

large measure of oil dependency, very little was done with the various coal-conversion technologies, and the center of activity of these programs shifted to the United States. Currently, the Office of Coal Research, of the Energy Research and Development Administration, is pursuing a large number of these technologies to and through the pilot plant level, and is conducting detailed research and development into the merits of competing technologies with basically the same objectives. Of particular interest, given the state of many of Europe's smaller mines, are the in-situ gasification programs now in early stages of development; if successfully implemented in the U.S. they could have considerable implications for Europe — particularly in the revitalization of closed or played-out mines (given the appropriate geological structures, of course).

Oil Shale

If this paper were written a year ago, the statement would have been made that there will be a potential area of long term technology transfer in oil shale development. While the U. S. has the world's largest oil-shale deposits, oil shale occurs worldwide; it has not been exploited, however, because of high cost, energy intensive development requirements. Recent U.S. "second thoughts" on oil-shale exploitation does not negate the potential of technology transfer in the exploitation of this resource. It rather reflects the fact that the original systems for developing U.S. oil shale resources (very large scale, energy intensive, water intensive, and expensive technologies) will apparently not be used. Alternative processes, and particularly in-situ development of oil shale (probably still two decades away) are under active study. Nuclear in-situ developments have not lived up to their previous expectations, and

will probably not be the vehicle of in-situ oil shale to oil conversion. Outgrowths of advanced tertiary recovery systems such as sophisticated fireflood systems appear to offer promise. If such systems are successful, their application to oil shale deposits elsewhere would be highly likely.

Open-pit Mining and Land Reclamation

One of the reasons that open-pit (or opencast as it is termed in Europe) coal mining has not been common is the intensive use of the land in Europe which precludes large areas of the surface for mining. New surface mining regulations, attendant to the opening up of U.S. western lignite deposits, will, in varying degrees of severity, require a high level of land reclamation and restoration. It may be that new and innovative techniques will emerge to meet this requirement in an economical fashion, and will permit surface mining to be feasible in Europe to a greater extent than is currently the case.

4.3.4 Nuclear Fuel Enrichment

A discussion of the requirements of Western Europe for electricity and the anticipated growth of nuclear power is contained in Appendix B. Because of the potential implications for U.S. sales overseas, the safeguards problem of transporting fuels, and the concern for the development of fuel enrichment facilities outside the U.S., a summary of projected fuel enrichment requirements has been included within this section on technology transfer.

Enrichment Facilities

Figure 4.1 shows the total world accumulative enrichment supply and demand curves through 1985 as developed prior to the oil embargo by the Atomic Industrial Forum in a 1972 report.[16] It clearly implies a shortage of enrichment capability in the free world by the early 1980s. On the basis of the curves shown, there will be a need to start up two large enrichment facilities (7000 metric tons of separative work units (SWU)) at the beginning of 1972, and at least four such plants by 1985. This obvious need has led to the push by the Europeans, under the Eurenco (European centrifuge program) to develop gas centrifuge plants and has led to a push in the United States to allow private industry to build new gaseous diffusion plants. Present plans by the private industry consortium of Uranium Enrichment Associates (UEA) call for building a 9000 metric tons of SWU plant by the early 1980s.

Recent developments since the oil embargo considerably cloud the picture as to the timing and magnitude of any future enrichment capacity shortage. The push by the Europeans to expand nuclear power to save oil imports would indicate a worsening of the enrichment shortage; however, recent economic developments have caused a considerable slowdown in nuclear plant construction in the U.S., and there are indications that several European countries are having trouble raising the capital needed to develop nuclear energy rapidly and nuclear plant starts are being delayed. Over the long run, a rise in the price of oil should mean an expansion in nuclear power which will require additional separative work. However, energy conservation measures in the U.S. and Europe, coupled with slowdowns in economic expansion and capital shortage problems seem to have slowed nuclear plant construction, indicating a few years

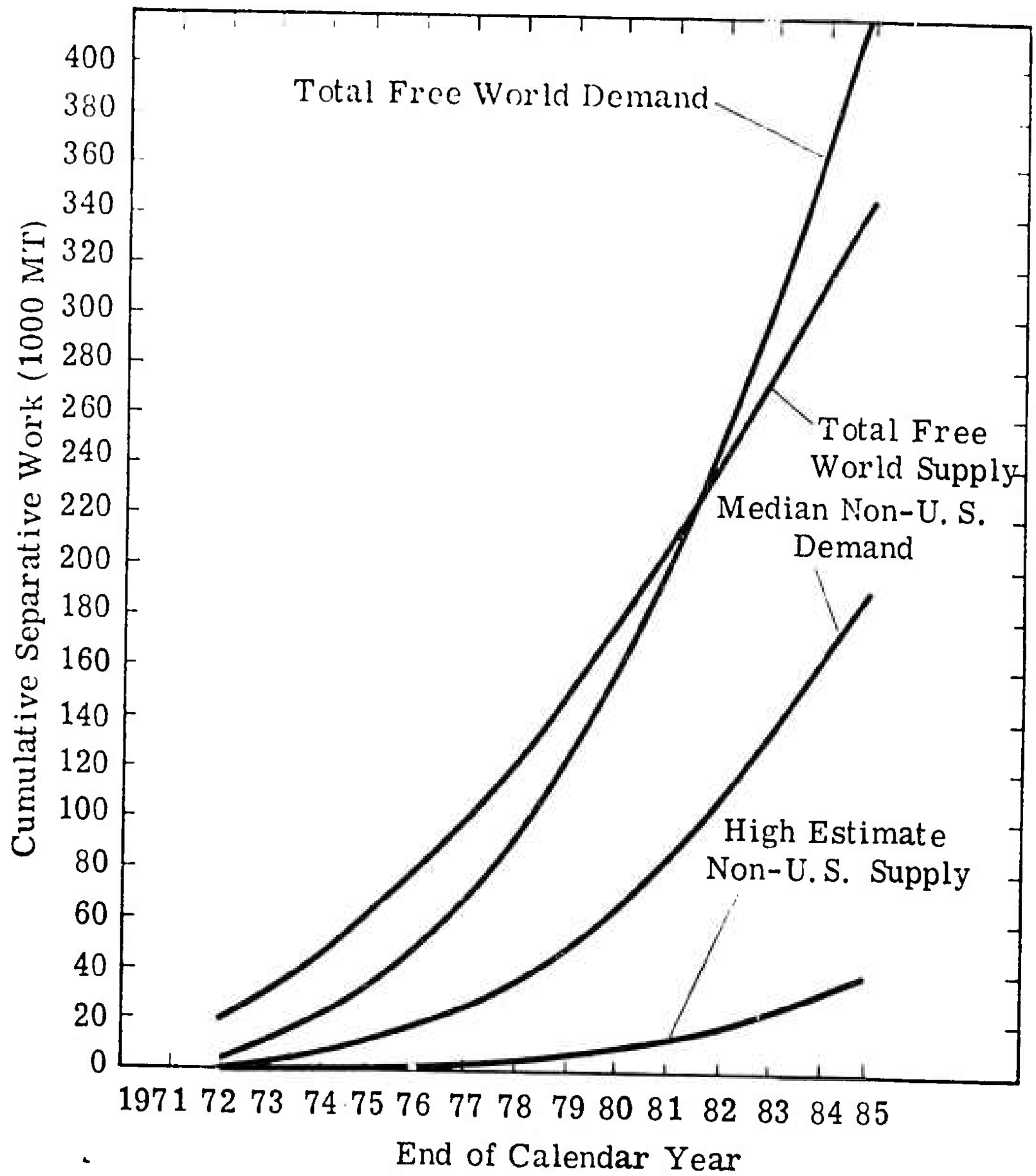

Figure 4.1. Cumulative Free World Enrichment Supply and Demand

delay in the time before new enrichment capacity will be needed by the free world. Thus, there still appears to be an obvious need to develop new enrichment capacity, but the period before any enrichment shortage may occur may well step from the early to mid-1980s.

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APPENDIX A

MAJOR DOMESTIC ENERGY RESOURCES OF WESTERN EUROPE

A.1 INTRODUCTION

Two major energy resources are available to Western Europe; one is a traditional source – the ample reserves of both thermal and metallurgical coal of the nations of the continent and the United Kingdom. The other is a new source – the vast oil and gas reserves that lie beneath the North Sea. The North Sea's potential as an energy resource first manifested itself in the coastal areas of central Britain, and subsequently in the 1969 discovery of the giant gas field at Gronigen, the Netherlands. It is in the North Sea that the major hope of Western Europe lies. It will offer an ample, accessible, and politically stable source of oil and gas but will not provide true energy independence, and it will not come cheaply. Costs of equipment and labor and the incredible investments required to cope with the appalling weather of the North Sea have driven the costs of a deep North Sea well up six and eight times the cost of a similar well in the Middle East.

Europe's traditional reliance on plentiful domestic coal has given way, over the past three decades, to reliance on more flexible, cheaper, and more socially acceptable Middle Eastern oil. Although most of the countries of Europe had small quantities of domestic oil (Austria had the largest supplies), they were in small fields, and could not support an extensive pipeline network or large refinery complexes. The availability of Middle Eastern crude changed that pattern

and huge refineries and petrochemical complexes were constructed not only in the areas of the major ports (Rotterdam, LeHarve, Genoa, Marseilles, Southampton), but also inland, and were supplied by a rapidly-spreading network of international pipelines. With the exception of the metallurgical industries, oil began to replace coal throughout much of Europe. The gas discovered at Gronigen introduced an even more desirable domestic and commercial fuel, and gas began to displace both oil and coal. Since coal is a labor-intensive industry, and was beginning to require ever-increasing government subsidies, only those countries with a vested interest in maintaining a large coal labor force (e.g., the U.K. and West Germany) made a concerted effort to arrest the decline in coal usage. Coal had essentially vanished from the commercial and residential sectors and was rapidly being displaced in the industrial sector when the embargo of 1973-1974 caused the situation to be reviewed. That review is still in progress, and is discussed in the coal section (Section A.3) of this Appendix.

A.2 NORTH SEA OIL AND GAS

A.2.1 Background

Vast oil and gas reserves in the North Sea may place this oil province among the most significant in the orld. Its reserves are still essentially undefined, but are continually escalated as new finds of major fields within the area are reported. Since the North Sea fringes much of industrialized Europe it offers potential to relieve the EEC and the rest of Western Europe from dependence upon the Middle East. Norway already exports oil[1]; the U.K. was once

expected to export oil by 1980[2]*, and the Netherlands will soon be able to use not only its va ˜ronigen gas fields, but also its extensive offshore gas fields as barter to assure a continuing supply of North Sea oil. Under current energy-sharing agreements, once the supply and distribution facilities planned for the North Sea are in place, Western Europe may anticipate a decade of lessened dependence on imported energy sources.

The size of the North Sea reserves, and their significance may be interpreted by the following statement of Dr. V. E. McKelvey, Director of the United States Geological Survey.

> ... World-measured reserves of oil in 1971 totaled 633 billion barrels of which 100.9 billion barrels or 16% lie offshore.... For natural gas, world-measured reserves in 1971 totaled 1,802 trillion cubic feet, of which 131 trillion, or 7% lie offshore.[3]

1973/74 estimates for the North Sea place 15.9 billion bbls of oil and 86.9 trillion cubic feet** of gas lying in commercially accessible and exploitable fields.[4] This represents an estimated 16% of all the world's offshore oil and 66% of the world's offshore gas, a significant asset for industrialized Western Europe.

Serious problems exist, however, in the exploitation and development of this vast province and the transportation of oil and gas to demand centers. Production platforms that must supplant the exploration drillships are extremely costly. Pipelines are also very

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* Although 1974-1975 politico-economic constraints may hinder development and delay this outcome.

** Late 1974 revised estimates place gas reserves at 95.3 trillion cubic feet.

expensive and are difficult to lay under the weather conditions in the North Sea. Offshore loading buoys and facilities not only are costly but frequently cannot be approached and moored-to by tankers because of weather extremes, and severe storms continue to cause excessive downtime on exploration rigs and drillships. Yet the potential value of the area is so enormous and so critical to Western Europe that a drilling and exploration program of unprecedented scope continued through 1974, with new finds reported almost weekly. The ratio of producing wells to dry holes was consistently more favorable than expected from conventional land and offshore exploration (with the exception of the Persian Gulf).

A series of giant fields south of the 62d parallel definitely establishes the North Sea as a major oil province (Figure A.1). These discoveries are all the more fortuitous since initial knowledge of the offshore geology and structure was limited and the formations were thought to be basically non-complex. Exploration and seismic profiles portrayed a pattern of considerable structural and tectonic complexity. Known producing horizons were displaced from their initially-plotted areas and levels and appeared in locations and attitudes different than those originally predicted. This geologic complexity has reflected, to date, disappointing shows in the Danish and West German sectors, but has apparently revealed greater reserves in the U.K. and Norwegian sectors than previously believed. Particularly surprising has been the extension of the petroliferous areas south of the 62d parallel, nominally considered to be the upper bound of the North Sea. It has only been a shortage of deep-water prospecting rigs and very severe weather that has limited exploration in these more northern waters, to seismic and magnetic profiles.

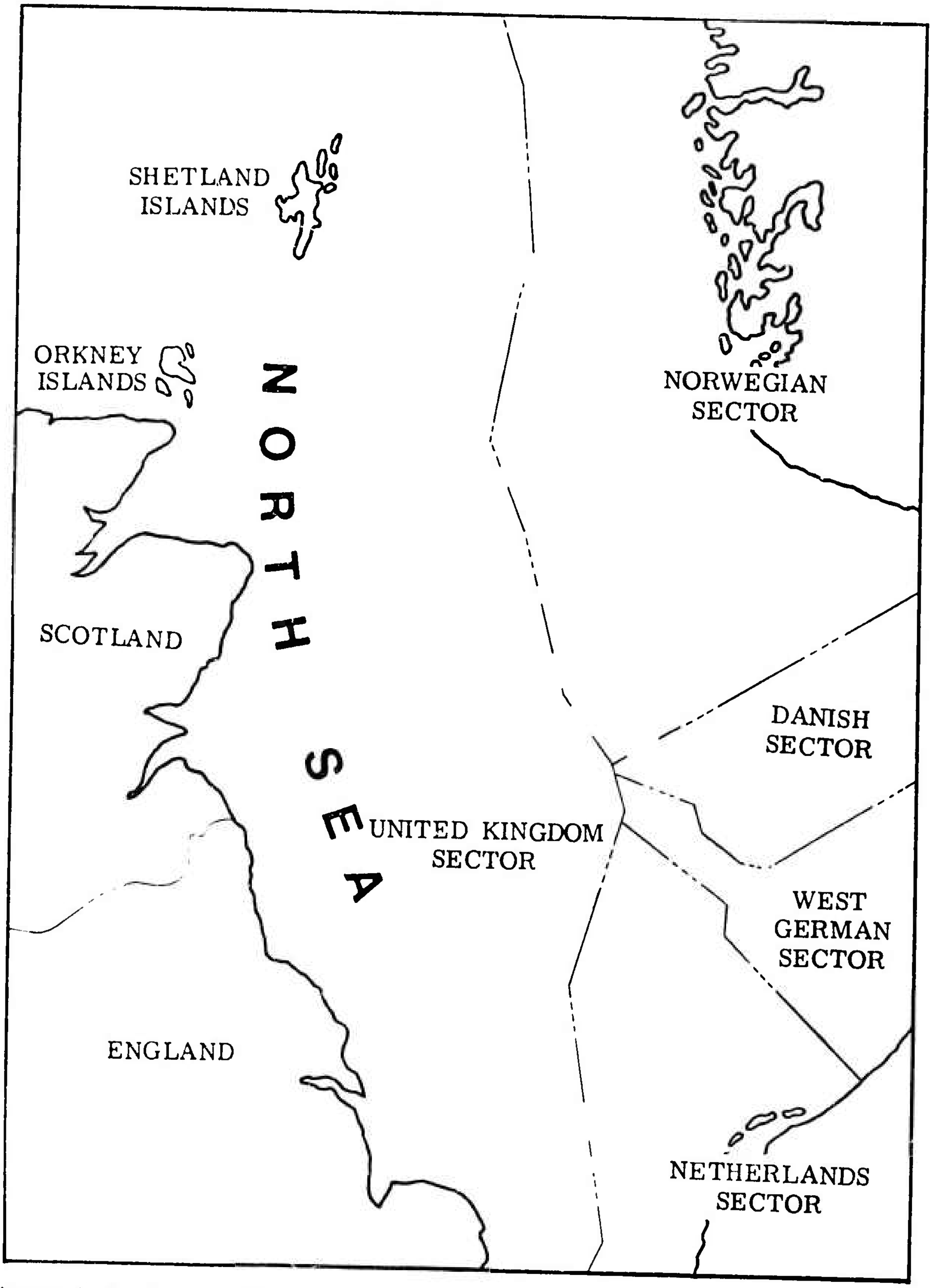

Figure A. 1. Sector Divisions of the North Sea for Oil and Gas Development

The tendency has been to establish "step-outs" from known producing areas rather than take the more expensive and more risky course of exploratory drilling.

A.2.2 General Description

Boundaries of the North Sea basin are somewhat amorphus, but, with the 62d parallel as the northern boundary, include approximately 280,000 square miles (the same area as the state of Texas). Initial estimates, subsequently upgraded, were that oil-bearing structures occupied nearly 90% of the North Sea basin.(5) With a progression of findings in the northern latitudes, and with the area north of the 62d parallel remaining to be explored, the area containing oil-bearing structures has been postulated to be significantly greater, although the economic feasibility of production in the northern region remains a subject of debate. Based on 1972 data, the North Sea was estimated to have reserves approximately 25% those of Texas. Each new discovery, such as the impressive new Statfjord field discovered during the 1974 exploration season and considered to be the largest field yet discovered in the North Sea, confirms these estimates. Additionally, exploration to the north and east of the Shetland Islands and external to the North Sea basin indicates that oil may be present in the Norwegian Sea, the Irish Sea, the Celtic Sea, and extensive other areas initially thought to be only of minimal geologic promise. Increasing ocean depths generate requirements for further development in drill rigs and platform technology. In general, in deeper waters and severe sea the use of drillships and jack-up rigs has given way to various types of semi-submersibles and platforms of incredible dimensions. Some of these new systems have proved themselves well;

others are highly questionable (a new semi-submersible rig, only one week on the job, capsized in the winter storms of 1973 for example, and a sister rig of similar design was heavily damaged). Finally, entirely new systems of offshore storage and deep-water pipelines are being developed. Vast sums of money are involved.

The North Sea has long been considered a potential oil and gas producing area but development speeded up during the late 1960s. Three events, essentially independent of the "energy crisis," precipitated development of the area:

- Discovery of the giant gas field at Gronigen, Netherlands
- Signing of the Geneva Convention on the Continental Shelf by all the countries on the North Sea, along with general agreement on offshore boundaries
- Maturation of a new generation of deep-sea exploration platforms and vessels capable of operating (and surviving) in areas in which conventional "offshore exploration" was thought to be impossible.

A.2.3 Early Phases of Exploration

North Sea development began, on land, with the discovery of the giant Gronigen gas field in the Netherlands in 1969. Gronigen gas is found in a Permian Sandstone, which has the same geological characteristics as a formation found in Yorkshire in which British Petroleum (BP) had found similar, although considerably smaller commercial gas. In adjacent offshore waters, BP brought in the West Sole field in 1965. Close by a number of large offshore producing gas wells were brought in during the Mid-1960s in the U.K. sector of the North Sea. A series of gas fields based on these wells were then

defined. Production facilities, pipelines, and terminals followed, and soon such fields as Lehman Bank, Hewett, Viking, Indefatigable, and West Sole were serving much of the U.K., displacing coal in the residential and commercial markets. All these fields clustered in an area basically due west of Gronigen, in relatively shallow waters. It was only through the intensive gas exploration activities in the southern North Sea basin that the possibility of the presence of oil in large quantities became apparent.

Geological exploration indicated that more recent sedimentary formations lying above the gas-bearing Permian Sandstones of the Gronigen and U.K. gas fields might well contain oil. In 1968 Phillips Petroleum made a strike in Norwegian waters near the Norway/U.K. sector boundary in Tertiary formations[6] (70 million years old compared to the mid-200 million age of the Permian gas horizons). The strike was not commercially significant given 1969 crude prices, but it was invaluable in confirming the presence of oil in at least one horizon of the extensive Tertiary formations of the North Sea. Phillips followed up with a major strike at Ekofisk, and brought in a giant field. Ekofisk and a series of subsidiary structures were explored and the area developed into what is currently called the "greater Ekofisk Area."[7]

Considerable quantities of gas were found both in association with the crude and in separate horizons. A million barrel concrete storage platform was floated to the field, sunk into place, and served as the collection point from the clusters of wells that were being drilled in the Ekofisk complex, planned to eventually contain 30 producing wells on three permanent platforms. The first platform, installed in the spring of 1974, permitted the first development well

completion. The gas, however, proved more of a problem than a blessing. Gas flaring was forbidden, both as a waste of a natural resource, and a potential requirement for maintaining reservoir pressure. Although contracts were placed in short order for a gas pipeline to Emden, W. Germany, the presence of extensive gas reserves in the Ekofisk area hampered the development of the field as a major petroleum producer. The million barrel concrete storage tank (the largest object ever constructed and floated by man) was converted from a storage and loading facility to the additional role of a gas injection facility, to, in short, keep the gas in place until the Emden Pipeline was constructed. Production from Ekofisk fell well below expectations during the period 1972-1974.[8]

Parallel development in U.K. waters, with basically similar exploration and development programs, was underway. A few development wells were drilled and a significant strike followed. Finally, a major discovery was made in the "Forties Field" at latitude 57° 47' N, also in the Tertiary formations, and the U.K. North Sea program was underway at an even more rapid pace than Norway's. In the course of oil and gas exploration, one major find essentially "proves" a producing horizon and leads to rapid development of additional fields, some nearby, others where the producing horizons were known to exist. In a manner similar to the U.S. off-shore leasing program, the U.K. placed a large number of blocks up for lease in the northern part of her sector, all the way to the 62d parallel. Development of the North Sea had, by 1971, begun in earnest. Field after field was brought in as the North Sea proved to be one of the world's major oil provinces.[9] Serious major technical, economic, and geopolitical problems remained to be resolved, however, before the area could begin to make a substantive contribution to the energy independence of Western Europe. The problems are still outstanding.

A.2.4 Geneva Convention Seabed Applications to the North Sea

In 1964, all of the countries with North Sea coasts agreed to the principles of the Geneva Convention of 1958 on the Continental Shelf (represented by the "median line concept") as being applicable to the North Sea.[10] In summary, coastal nations possess "sovereign rights over natural resources below the seabed out to a water depth of 200 meters, or deeper if mineral exploitation is possible. Specifically, the law states:

> (a) the seabed and subsoil of the submarine areas adjacent to the coast but outside the area of the territorial sea, to a depth of 200 meters or, beyond that limit, to where the depth of the super-adjacent waters admits of the exploitation of the natural resources of said area; (b) the seabed and subsoil of similar submarine areas adjacent to the coasts of islands.

The countries of the North Sea littoral have in general agreed on the boundaries, although several disputes have developed in this area since the initial agreements. Figure A.1 shows the initial apportionment using base-lines and the Geneva Convention as criteria. Each country assigned concessions within their designated areas:[6]

> Denmark: A. P. Moller Group for 10-year exploration period. On areas in which production is established, concessions continue valid for 50 years. Moller Group formed nucleus of "Dansk Underground Consortium" (DUC) now operating.
>
> Federal Republic of Germany: "German North Sea Consortium" (GNSC). Concessions assigned on provisional basis with 3-year extensions as required. Specific requirements for an established pace for exploration and drilling.

Netherlands: A series of blocks ranging from 390 to 420 sq km is established. Blocks are leased under the following terms:

- License awarded for 55 years.
- At the end of ten years half of the original area to be released.
- Rentals charged and development obligations expressed through expenditures, rather than level of effort. Government reserves to participate up to 40% in commercial gas finds. No initial royalties, up to 16% charged as established production levels are achieved.

Norway: Norway has a complex system which has varied extensively since North Sea oil and gas were discovered. Norway's position has varied considerably since the initial euphoria of the Ekofisk and associated discoveries, and in 1974 exploration and development were sharply reined-in in favor of conservation. The basic block and allocation system has been retained, but confronted with the enormity of their holdings, and the possible economic consequences of rapid-large-scale development the Norwegian government has had to pause for a careful second look at their leasing policies.

Their area is divided into a block of 500 to 570 sq km, with a 46-year license for exploration, development, and production. After 6 years, 25% of the originally leased area is to be released and reverts to the government; 9 years later an additional 25% reverts. Lease obligations include requirements for seismic exploration, exploratory and development wells. The government charges royalties and retains the option to participate in the overall development program. Newer, more restrictive agreements have been initiated as the number of finds increases.

Norway remains the most important North Sea oil producer.

United Kingdom: The U.K. has established a series of blocks varying from 210 to 240 sq km. Initial allocation was awarded by competitive bidding (1971); subsequent allocations are based on "discretionary basis" on 46-year licenses. At the end of 6 years, licensees surrender half their acreage to the government, but may retain balance for an additional 40 years by paying an annual rent. In producing areas, royalty is 12-1/2%. With the 1974 accession of the Labour Government, new taxes and new terms of government participation have been proposed. These are further discussed in Section A.2.6 of this Appendix.

France, Belgium: North Sea sectors are negligible. Limited exploratory seismic work in the northeast section of English Channel proceeds with minimal results.

A.2.5 North Sea Reserves

General

It is appropriate at this point to distinguish between two definitions of "reserves" which are somewhat contradictory. On the one hand, "reserves" means all the oil or gas in a given field or area that can be extracted by any means, with any currently viable technology. Because reservoirs lose pressure and oil "migrates" into inaccessible voids, even enhanced recovery methods cannot assure that more than 30-40% of the oil in a given reservoir pool, or field, can be recovered. Thus when referring to reserves in the absolute sense, the total "recoverable reserves" rather than the total estimated volume is the datum of reference. On the other hand, reserves are often equated with "economically recoverable reserves." In such cases, "reserves" in a field may grow if the selling price of the crude increases. The U.S. "reserves" were depleted rapidly when cheap Middle Eastern oil made it uneconomical to operate

higher-cost fields in the "Lower-48 States." However, U.S. "reserves" have expanded (essentially without benefit of exploration) as a result of higher imported oil prices. The North Sea situation is similar. Some reserves and estimates of reserves are based on continued exploration and development; some are based on incorporating previously-ignored "uneconomic" fields, in which the cost of development was not feasible at the then-selling-price of oil. Presumably, faced with \$12/bbl OPEC oil, \$9/bbl and possibly even \$11/bbl North Sea oil will be an attractive investment, and "reserves" will grow accordingly. In like fashion \$9/bbl oil may not justify expensive enhanced recovery techniques, widely practiced in the U.S., but \$11/bbl oil would make this a feasible activity, and shut-in fields and marginal fields in the North Sea would be developed under these economic influences. To date, however, most of the escalating "reserves" in the North Sea have resulted from exploration and development, not from economic fluctuations.

Reserves After Initial Exploration

Reserve estimates of the North Sea steadily escalated as development continued. In 1972 they were cited as:[6]

- 7 billion bbls crude and condensate known recoverable
- 12 trillion cu ft gas (both associated and non-associated)
- 1.5-2.0 billion bbls crude possibly non-commercially recoverable
- 3.8 trillion cu ft gas possibly non-commercially recoverable.

It should be noted that the 1972 definition of non-commercially re-coverable was made in the context of 1972 prices, and well before the embargo.

By 1973, additional exploration and the spudding in of the initial development wells increased estimated reserves as follows:(5)

- 11 billion bbls crude and condensate
- 60 trillion cu ft gas.

An interesting aspect of the 1973 figures, particularly the increase in the estimates of gas, was the subsequent discovery of gas in association with oil horizons in the central and northern North Sea basins. Thus Ekofisk, a major Norwegian field originally thought to be primarily oil (although associated gas was to be used for re-injection to sustain underground pressures), was found to have large quantities of commercially viable gas. A pipeline was initiated to Emden, West Germany, to begin deliveries in 1975. In like fashion, the Frigg Field, originally thought to be primarily an oil producer, has shown sufficient "surplus" gas to warrant the construction of a pipeline to Northeast Scotland.

In 1974 several more giant fields of both oil and gas were discovered in the U.K. sector, and three were placed into active development. At the same time on the Norwegian side of the median line, the Statfjord field was brought in, with potential production greater than or at least equal to the Ekofisk complex. The first two wells, for example, flowed at 10,000 and 12,000 bbl/day, large by even Middle Eastern standards. Thus, at the close of 1974, estimates of recoverable reserves were again increased:(4)

- 15.9 million bbls of crude
- 86.9 trillion cu ft gas.

Reserves-Outlook 1975

Worldwide inflation and money markets have seriously impacted determination of the North Sea reserves. What constitutes a viable economic venture in developing a field fluctuates almost daily in the capricious climate of costs, taxes, and proposed majority government participation. Some fields that were "added" to the reserves of the North Sea, in the context of $9-11/bbl oil, have currently been "withdrawn" because of potentially confiscatory taxation policies. At this writing intense discussions of this matter are proceeding in the U. K. and Norway. Meanwhile the cost of everything else involved in the development of fields has risen astronomically. Originally, the estimated development costs assumed investment of $1000 per barrel per day for eventual production from a field;* by 1972 the figure had doubled; by 1973 it was $2500; and by the end of 1974 the working figure for large, well established, high-production fields such as the "Forties" was $3000. The smaller, marginal fields were beginning to "drop out" of the reserves estimates, even at a potential $11/bbl selling price. Government control and taxation of development may have to be accompanied by government subsidies if the potential of North Sea reserves is to be realized, and if Europe is to minimize dependence upon OPEC oil. [11, 12]

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* The figure of $1000 represents the pre-production investment per barrel per day of production. The following expenses are included: exploration; exploratory wells, development wells, and delineation wells (drilled from drill ships or semi-submersibles); production platforms and production wells; pipelines and/or terminal storage facilities. The cost of acquiring the lease and production operating costs are not included.

International financing is becoming harder to obtain. The Oil and Gas Journal, November 4, 1974, stated:(13)

> ... bankers were shocked at the enormous amounts of money required for development of North Sea fields — about $1 billion each for Forties and Ekofisk, including development wells, platforms, transportation systems and shore facilities.
>
> (International bankers felt that)... financing North Sea activities has 'lost a bit of its earlier glamor' ... in fact there is a loss of financial confidence in operations there....
>
> It is possible that a number of groups which discover oil in the North Sea may be quite unable to raise money for development because they lack either operating capability or financial growth.

Although the article was referring to U. K. developments in the North Sea, the "money crunch" as well as a current shortage of rigs has inhibited all development. Further exploration and development of North Sea reserves is expected to slacken in 1975 in favor of applying fiscal and manpower resources to production platforms, offshore storage facilities, pipelines, exposed-location single point mooring facilities, underwater storage, spar-type platforms, and the overall development and transportation infrastructure. Such investments aspire to assure that North Sea oil and gas may, belatedly, begin to pay for itself, recoup the tremendous initial investments made, and thus subsidize further investment.

Another inhibiting factor is typically politico-economic. Norway, with a population of approximately 4 million, has chosen to cut back drastically on the issuance of exploration and development leases, and concentrate instead on establishing pipelines and

production platforms.[14] The U.K., beset by strikes, faces struggles over the Labour Government nationalization and taxation policies.[15] W. Germany, Denmark, and the Netherlands are expected to continue exploration, to hedge against another interruption of oil supplies. W. Germany has not developed significant finds in her sector, but will share in the Ekofisk natural gas reserves via a pipeline to Emden, currently under construction, and an additional pipeline from the Placid field in Netherlands waters. Germany has drilled a series of dry holes in her sector, but is expected to apply lessons learned and advanced exploration technology to further exploration and development in 1975. Denmark, who actually brought in the first commercial grade North Sea oil in 1967, under considerable secrecy, has not been able to exploit the Dan fields, even though the geological horizon tapped is highly prolific elsewhere in the North Sea. The current state of development of the Dan field does not warrant pipeline construction; the approximately 4000 bbl/day are transported, weather permitting, by tanker. The Netherlands is expected to continue exploration for gas, although non-commercial shows of oil have been reported.[4]

Based on geophysical indications, current forecasts are that the potential recoverable reserves of the North Sea may lie in the 30 billion bbl range, or just slightly less than those currently estimated for the United States including Alaska. Evidence from the past year indicates that these figures are not exaggerated, and may well be exceeded.

A. 2. 6 The United Kingdom

Britain has encountered both euphoria and depression in assessing the impact of North Sea oil and gas on her domestic economy. Prior to the 1973 embargo and massive world inflation, the U. K. was felt to be on the threshold of energy independence, as find after find was reported from the North Sea, and predicted reserves escalated almost weekly. Even at this writing, the U. K. could become an energy-exporting nation by the mid-to-late 1980s, provided rapid development of the necessary production and transportation infrastructure is carried out. However, the realities of the economy of 1975, the soaring costs of infrastructure development, labor unrest, nationalization and taxation policies of the U. K. government, and the "tight money market" have all combined to place a massive brake upon U. K. North Sea development. The reserves are there; the U. K. is developing them faster than any other country in the North Sea, but in the meanwhile the cost of OPEC oil is taking its economic toll. The timetable has been set back considerably, but the future potential of the North Sea in attaining energy independence for the U. K. still exists. Production estimates of gas and oil fields for the U. K. are summarized below. 2 billion, 875 million cubic feet of gas are currently coming from the North Sea each day, with an additional 1 billion, 500 million expected in the next year or so. Only 300, 000 bbls of oil per day are currently flowing to the U. K. from the North Sea by tanker from the giant Ekofisk complex. But when pipelines under construction are completed (along with shore facilities) this figure is expected to increase dramatically.

U.K. Gas

In the southern North Sea basin, the large network of gas reservoirs has been connected to the internal U.K. pipeline system and is on stream, supplying an ever increasing portion of central and southern Britain's energy needs. As part of the overall master plan, gas is beginning, locally, to supplant oil as an industrial heat source. Table A.1 lists gas reservoirs online or to be developed. Additional gas exists in U.K. waters under two geological constraints. Some lies in small fields, while other (often substantial quantities) is associated with oil. Since the supply is insufficient to justify a pipeline, it is re-injected, to maintain reservoir pressure. Late 1974 estimates are 116 trillion cu ft of recoverable gas reserves in U.K. North Sea waters. The economics of new pipelines or establishing tie-ins with existing or to-be-built pipelines as well as the cost of establishing production platforms will decree whether fields will be developed over the next decade. The probability of additional finds (possibly major) in southern North Sea waters in U.K. sector is high, and ability to tie-in pipelines to the cluster of fields between 54-55^{o} N appears feasible. Additional finds north of the 62d parallel would impose severe logistic problems and be very expensive. Gas fields within Norwegian waters are also potential sources for the U.K., as the gas must be either exported (which means a pipeline), or re-injected. In light of the limited ability of Norwegian industry and commerce to absorb and utilize such quantities of gas, and the cost of a gas pipeline across the Norwegian Trench, export to the U.K. is a logical alternative.[16]

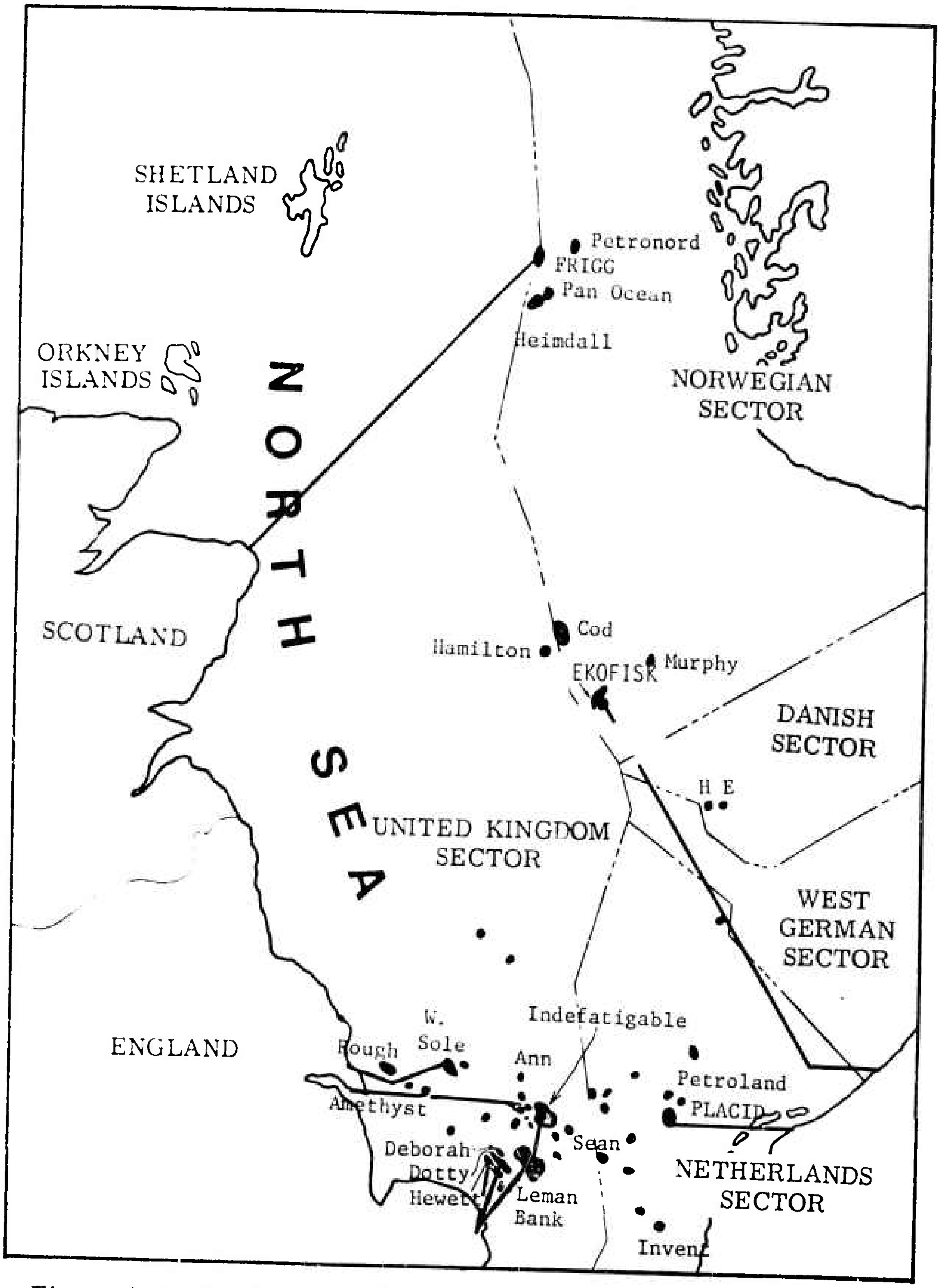

Figure A.2. Gas Fields of the North Sea Under Active Development with Planned or Operational Pipelines.

Table A.1. Major North Sea Gas Sources for the United Kingdom — 1974

Field	Status	Production Million cu ft/day	Reserves (1974 Est.) Trillion cu ft
Leman Bank	Producing (2 fields)	1400	12.0
Hewett	Producing	500	4.2
Viking	Producing	400	4.0
Indefagitable	Producing	275	8.0
West Sole	Producing	300	n.a.
Frigg	Platform and pipeline being built to Scotland and U.K. net	1500 (contracted)	11.0

U.K. Oil

The United Kingdom has moved rapidly into a dominant position in the development of offshore oil resources. Not only are fields lying on the U.K. side of the North Sea median coming into production, but the vast Norwegian complex of Ekofisk will soon be online. U.K. labor difficulties have slowed the construction of the Teeside terminal facilities, which will contribute up to 300,000 bbl per day of Ekofisk oil to the U.K. supplies. In the meantime, U.K. emphasis is directed toward their own giant "Forties Field." Labor delays in construction of the giant platforms from which the producing wells are to be drilled have set back the U.K. program reportedly from 6 to 8 months. "Highlander 1," a giant steel "jacket" weighing 23,000 tons was floated to its site and sunk into position on August 19,

1974, approximately six months behind schedule.* "Graythorp 1," a slightly smaller platform, had been installed a month earlier, thus giving the "Forties Field" a capability of becoming the first of the large U.K. North Sea fields to enter production. Work decks were subsequently installed, and all drilling and production equipment is expected to be in place by the spring of 1975. By mid-October, 1974 a critical phase had been passed and all pilings had been emplaced to secure both platforms against the expected winter storms. The installation of surface drilling and associated production equipment was well underway. Typically, however, all activities in the North Sea are severely limited by weather, causing unscheduled, but not unexpected delays, particularly in the critical pipeline link from the Forties to Scotland. A link between the Forties and the smaller Montrose field to the southeast has also been delayed, but the Forties is still expected to be producing 250,000 bbl/day and delivering it to Scotland early in 1975. From the sea terminal in Scotland, a land pipeline links central coastal Scotland and associated refineries.

Although the Forties will be the first completely U.K. system to be delivering North Sea oil to the U.K., discovery of several giant fields in the 1973-74 period has made all previous estimates of U.K. resources in the area obsolete. By mid-1974 proved crude sources either available to the U.K., or lying in the U.K. sector of the North Sea were as follows in Table A.2.

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* Production, launching, and towing schedules must also await the infrequent periods of good weather in which the delicate controlled sinking of the jackets must occur.

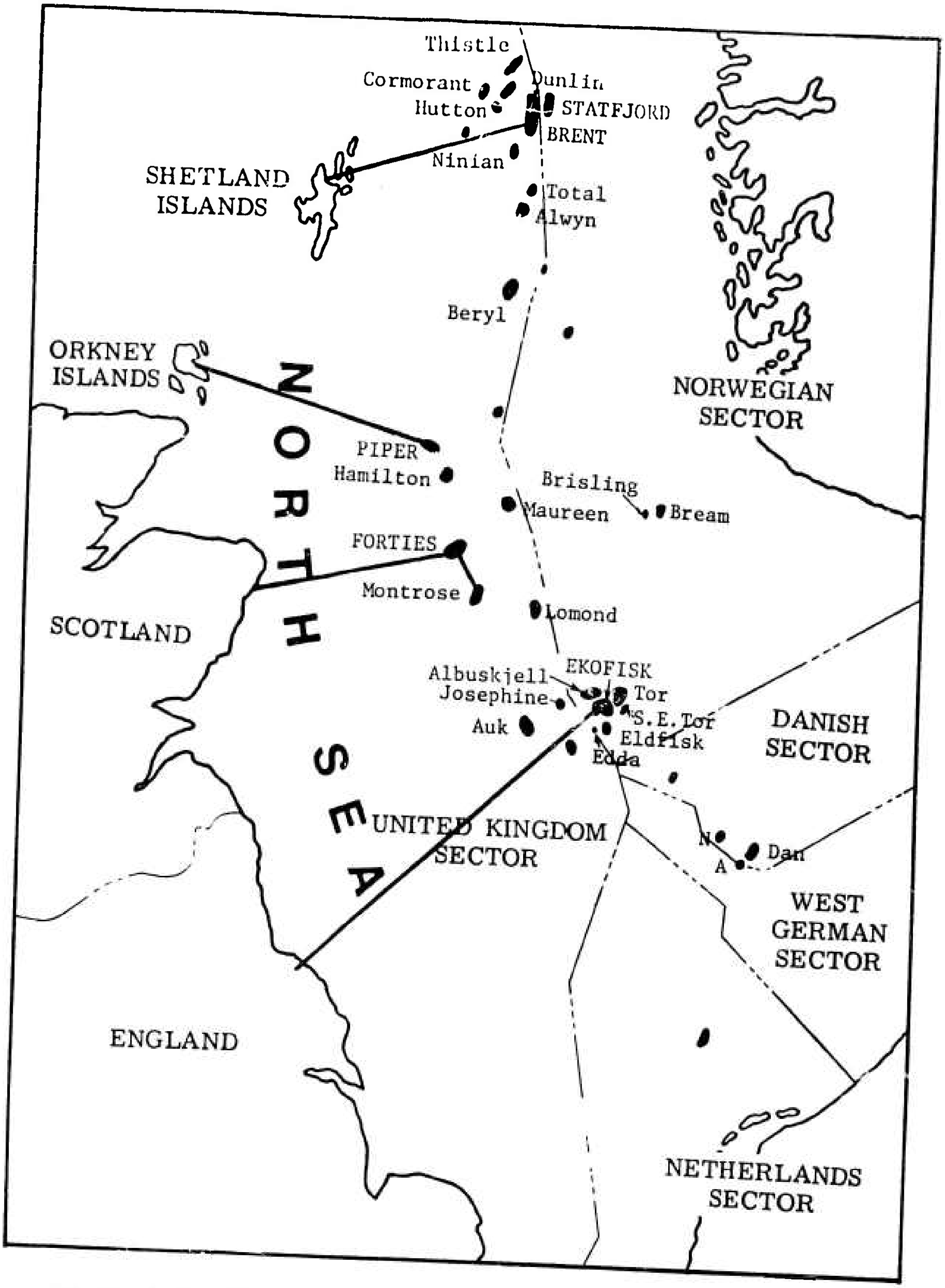


Figure A.3. Major Developed Oil Fields of the North Sea and Pipelines Under Construction or Operational.

Table A.2. Major North Sea Crude Oil Sources for the United Kingdom

FIELD	STATUS	EVENTUAL ESTIMATED PRODUCTION CAPACITY (bbls/day)	ESTIMATED PRODUCTION		ESTIMATED RESERVES billion bbls
			by 1980	by 1985	
Brent	Developing (P)	500,000	200,000	300,000	2.5
Forties	Producing (P)	400,000	200,000	300,000	1.8
Ninian	Developing (P)*	400,000	doubtful	100,000	1.8
Hutton	Developing (P)*	300,000	doubtful	doubtful	1.0
Piper	Developing (P)	220,000	50,000	100,000	0.9
Thistle	Developing (P)*	200,000	doubtful	doubtful	0.8
Dunlin	Developing (?)	150,000	doubtful	doubtful	0.65
Cormorant	Developing (P)*	150,000	doubtful	doubtful	0.65
Montrose	Developing (?)	50,000	doubtful	doubtful	Included in Forties Structure. Believed to be same geological structure as Ekofisk and included in Ekofisk Estimated Reserves
Auk	Producing (T)	45,000	30,000	30,000	
Josephine	Assessing (?)	100,000	doubtful	doubtful	
Argyl	Developing (?)	50,000	doubtful	doubtful	
Beryl	Developing (?)	100,000	doubtful	doubtful	
Andrew**	Assessing	Unknown - expected to be very large	No	doubtful	
EKOFISK	Producing (Primary UK)	300,000	Norwegian Waters	considered Import	2.5

(P) Pipeline under construction. Strikes have delayed completion of all pipelines, but will be operating below rated capacity by 1980. Producing wells to be drilled from platforms sequentially, gradually bringing up output through next decade.

(P)* Pipeline planned but not actively under construction. Complete transportation infrastructure (platforms and pipelines) probably not completed by 1980, possible but unlikely by 1985. Pipeline planned to link Brent (Pipeline under construction) with Thistle, Cormorant, Hutton, and Ninian. Economic factors very important in project, will probably be initiated in 1976/1977 and not expected to be on line before 1985.

(?) Current economic factors make further development of field questionable at this writing.

(T) Single-Point Tanker Buoy limits production. Since infrastructure investment comparatively small, will probably produce through 1985.

(**) Andrew is "sleeper" in scenario. If reserves are as large as postulated will justify major transportation infrastructure and associated platforms and pipelines. Appears to be good long-range post-1985 prospect.

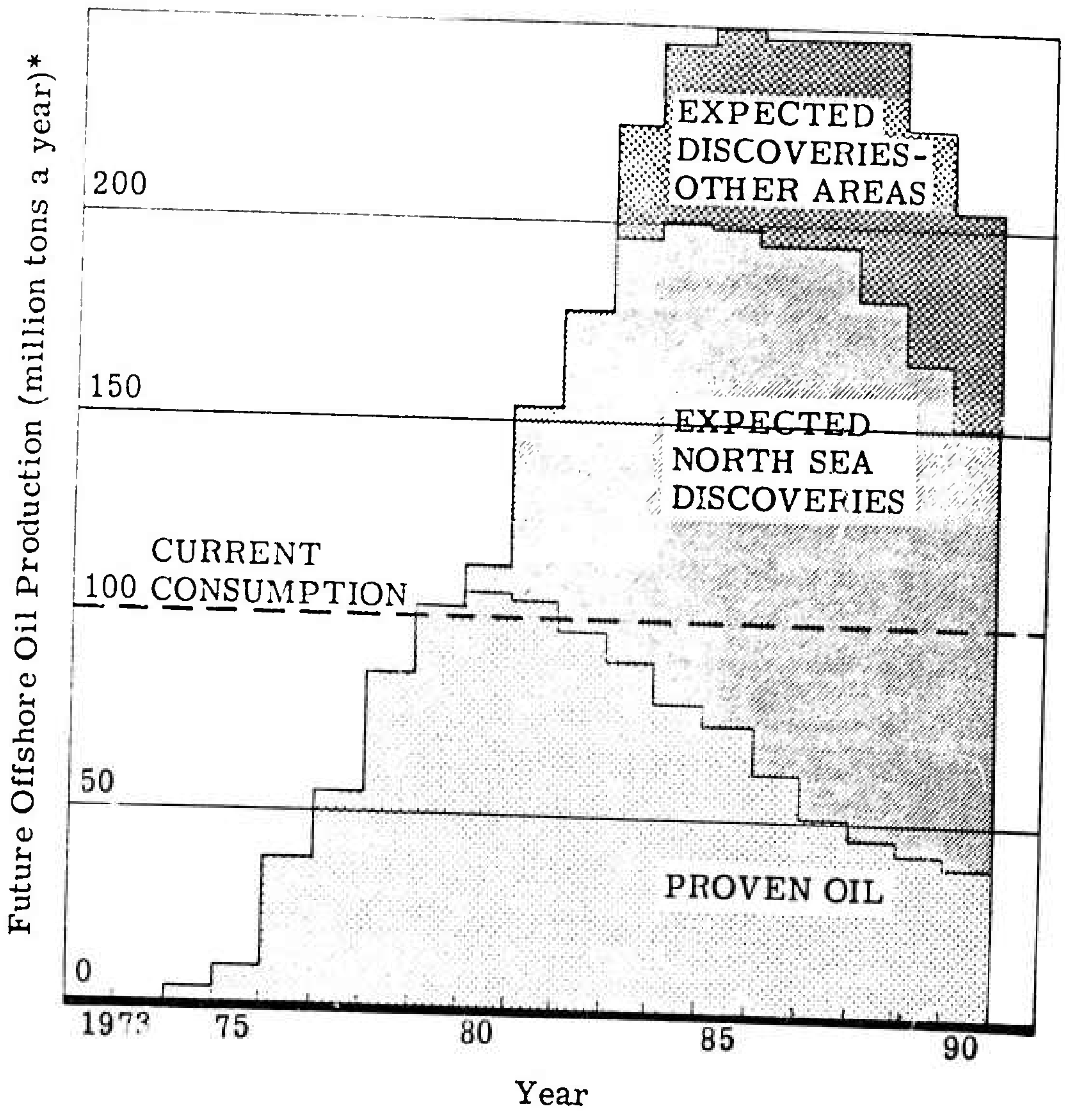
U.K. Energy Outlook

The energy future for the U.K. is highly mixed, and may be viewed from several aspects. To quote a special report, prepared by the American Petroleum Institute and published in the 11 November 1974 Oil and Gas Journal:(17)

> Oil discoveries in the British and Norwegian Sectors of the North Sea show even greater promise of improving Europe's energy self-sufficiency. On the U.K. side, existing reservoirs indicate an annual production rate of 100 million tons, or 2 million b/d by 1980. This may be doubled with new discoveries by 1983....
>
> ... Although the North Sea is hailed as Britain's salvation in the current energy crisis,... its promised output will go far to aid all of Europe in a difficult period.

The Economist in its 11 May 1974 issue(9) forecast a "British Sheikhdom" and stated that "Britain would be exporting large quantities of oil by the 1990s" (Figure A.4). On the other hand, a considerably bleaker view is taken by The Economist in its November 9th issue,(18) in an article entitled "Time to Get Tough About Energy." It starts off with a pessimistic subtitle, "Britain's lack of an energy conservation programme in the face of mounting debts is indefensible. The North Sea probably won't help until too late." The first paragraph develops the theme of the article:

> The British have been lulled into the belief that North Sea oil will save their country's bacon. But the oil payments deficit is piling up fast while Britain's own oil is coming out mightily slow. What is more, both trends may get worse and meanwhile Britain does nothing to discourage energy consumption which could save it anything up to one-fifth of its deficit....



* 100 Million Tons Per Year = 2 Million Barrels Per Day

Figure A.4. Optimistic View of U.K. Oil Position, Published in The Economist in May 1974

> ... There are two new factors that are likely to delay British oil production even further than it has been already by strikes, late deliveries of equipment and the sheer hostility of the North Sea. The first is the extraordinary rise in costs of North Sea production systems.... So will the Government's renewed determination to form a British National Oil Corporation to participate actively in the development of North Sea oil, a political move that will accomplish little beyond the old system of creaming off taxes and royalties, while duplicating the oil companies' own bureaucracies.
>
> But if quick salvation does not lie with the Texas of the North, what can be done?... undoubtedly in the short term the price mechanism offers the best chance...to bring oil realities home to the British public.... A small slice might be added on top of the value-added tax....

The article then goes on with a list of energy conservation strategies in the electricity and natural gas areas, discusses insulation, speed limits and topics essentially parallel to those put forward in the conservation option of the U.S. /FEA "Project Independence."

U.K. Oil — 1975 Outlook

The economics of 1975 and to a lesser extent, the politics of the autumn of 1974 mitigate against the immediate creation of the "British Sheikhdom" so optimistically forecast the previous spring. Although the reserves are in place, and escalate with each assessment, the production and transportation infrastructure necessary to convert them into a component of national economic sustenance and export potential of the U.K. have lagged badly. Daily U.K. press and economic reports connote gloom and serious problems. Britain's affiliation with the EEC implies certain "pooling" regulations that

have mitigated the enthusiasm for U. K. -financed North Sea development which would be, according to the September 28th Economist[19] controlled by Brussels. Economist goes on to state:

> These fears are not groundless. Article 24 of the Treaty of Rome forbids one member blocking trade with another. In some future supply shortage, this is just what Britain might wish to do. But the British Treasury looks to North Sea oil to balance its payments, not to run Britain's motor cars. North Sea oil makes excellent jet fuel, but it is extravagant to use for power stations. To pay for a heavier crude mix, Britain will need to put its own precious North Sea oil onto the markets of the world -- a strategic reality, whatever treaties say....

In January 1975, cries such as "Economic Dunkirk" were made in the British Press, as many of the major oil companies threatened to pull out of North Sea development entirely.[11] A devastating impact on development on both major and independent producers was forecast as the proposed taxes went as high as 76%.[15] Amoco Europe, in a series of full-page advertisements in the British Press, bluntly stated that it was prepared to pull out of North Sea developments and implied that other major producers were also so inclined. The alternative, given the proposed taxes, was a doubling of oil price (which would put North Sea oil higher than OPEC), or a loss of 2.4 billion dollars in future investments. Independents and smaller producers faced even bleaker prospects.[12] The result, according to the London Times of January 18th,[20] has been a serious split among U. K. economic planners; some favor a graduated rate depending on field production and size and others feel that operational costs (e.g., deep-water fields) should also be included. At this writing, no firm decision has been reached. The somewhat draconian taxation policies proposed earlier apparently were to be

modified in light of not only industry opposition, but a real fear among some in the Labour Government that they literally could kill the "goose that lays the golden eggs."

In summary:

- The North Sea reserves represent a tremendous energy asset for Britain.

- The economics of development and extraction, in the context of world inflation of 1974, are staggering and have caused serious "second looks" by the financing communities. This policy has already forced out the under-funded independents and small consortia, leaving the well-established "majors" to carry the development load.

- Frequent strikes and labor unrest have caused serious delays in development and exploitation — hence the North Sea is still a long way from returning even a small fraction of the initial and ongoing investment.

- The British Labour Government's traditional policy of nationalization of major industries has caused hesitancy in major private investment in new capital equipment, a slowdown that may not be felt for several years, but will further mitigate against a rapid influx of capital from North Sea development.

- Because of the aforementioned strikes and labor unrest, major capital equipment purchases are being made in Norway and France. A "Buy British" faction is currently active, which if translated into official policy would cause even slower development, particularly in the fabrication of production platforms, currently the most pressing requirement.

- Despite the constraints outlined above, the U.K. will probably become an oil-exporting nation by 1983.

- Estimated U.K. North Sea oil production: 2 m bbl/day by 1980 and nearly 5 m bbl/day by 1985.

A.2.7 Norway

Norway, the first country to benefit from the immense oil and gas reserves of the North Sea, is the first country to officially slow the pace of exploration and development. Despite close ties to the EEC and with full realization of the importance of Norwegian oil to Western Europe, Norway has opted against a short term, potentially inflationary influx of riches in favor of a more paced, controlled development, commensurate with the economic requirements of a country with only 4 million people. This position has been unpopular both with the numerous non-Norwegian consortia who have been carrying out exploration under lease in Norwegian waters, and with the "impoverished" northern third of the country who have a somewhat marginal economy based on fishing and lumbering. The latter feel that the income from Norwegian oil could and should provide social services, but the government has, at this writing, apparently opted for a "go slow" development pattern, in which the proceeds from leasing and production would be gradually phased in to the national treasury, with heavy governmental participation in production and development. By the end of 1974 this policy had already caused some international oil companies to reconsider the value of their participation in Norwegian North Sea oil and gas programs.(11)

Early Exploration and Development

The North Sea oil boom really began at Ekofisk in Norwegian waters and continued well into the late summer of 1974 when the Statfjord Field, almost on the 62d parallel, was brought in with indications that it would be "considerably larger than Ekofisk." Three wells at Statfjord indicated that field reserves were 2 billion barrels

of oil and 1.76 trillion cu ft of gas.[21] Ekofisk is expected to bring some 1 million bbl/day, putting some 800,000 bbl/day on the world market. If 1975 OPEC prices are sustained, Norway could realize about $9 million per day. Norway is not a member of OPEC (although it has been publically rumored that as a major oil producer it should join OPEC), and therefore OPEC prices could be considered blatant profiteering. Yet, a well in a Middle Eastern desert can be drilled for approximately 15% of the cost of those brought in in the North Sea, and platforms and pipelines are also much more expensive. Norway has spoken of "$9/bbl oil in the spring of 1974"[22] and has not changed position much since that time.

The history of exploration and development, and the reining-in of such activities almost has to be considered on a month-by-month basis. Throughout the past years it has shifted from an initial wide-ranging and enthusiastic plan of leasing and development, through a "second look" policy in which State participation (and revenues) were markedly increased, to a current "no-growth" leasing policy in which minimal leases have been offered under conditions of massive government participation and poor climate for economic return.

- <u>1970-1973</u>: Large blocks from 500 to 570 sq km[6]
  - License duration to be 46 years
  - After 6 years, 25% of original area released
  - After 9 years an additional 25% to be released
  - Acceptance of lease imposes requirements for exploration, seismic surveys and exploratory wells
  - Royalties imposed on discoveries
  - Government participation option.

- 1973 and beyond

  - Norway sharply restricted leases, adopted a policy of conservation based on Ekofisk revenues, lowered taxes, increased government spending, and took steps to avoid "embarrassment of riches."

  - 1973 Chronology:[23]

    - January: Prime Minister Trygve Bratelli held press conference announcing that "a new block in Norwegian North Sea waters will be awarded in March"

    - February: Finance Minister Per Kleppe urged "highest possible level" of government revenue from oil production

      : Trade Minister Jens Evensen stated that the government's take could amount to as much as 80% of oil company profits

      : Foreign Minister Knut Frydenlund suggested strengthening contacts with OPEC, and joining same when Norway became a net exporter in 1975

    - March: State issued white paper reaffirming desire of government participation at essentially all levels of exploration, development and production, and marketing[24]

      : Further awards south of 62° N were discouraged, but exploration North of 62° N was encouraged

      : Paper estimated "proved" reserves in Norway's North Sea sector were 2.2-2.9 billion oil and 17.7-21.2 trillion cu ft of gas

: Statement appeared in Oil and Gas Journal "Norway is trying to put a damper on exploration and development in its sector of the North Sea... desires its reserves to 'last 100 years'... only 14 concessions out of 28 applied for to be awarded.... Statoil (Government owned) only operator north of 62d parallel."(25) Government oil revenue predicted at $1.7 billion per year by 1978 and $2.5 billion by 1980.

— April: Phillips Petroleum, Major U.S. concessionaire in Norwegian North Sea sector, states "...Once they (the Norwegians) enter an agreement I think they're going to keep it." Further states in effect that restrictions under discussions apply to new concessions, and that such will not apply on fields already licensed. (25)

: Mobile discovers giant new field in Norwegian waters, northernmost to date, and on median line with U.K. concession area "largest since Ekofisk."*(26)

: U.S. Petroleum executive states Norway will honor contracts for $9/bbl oil. (27)

— May: Norway announces that only 10 out of 32 blocks are to be allocated and these to be adjacent to U.K. median line (possibly tapping same reservoirs). None north of 62^{o} offered. 175 companies offering. (28)

— June: Opinion poll carried out by Norwegian government showed that policy of high level government control and minimal exploitation by Statoil was endorsed by more than half the electorate. Environmental concerns, inflationary wages, and impact on fishing industry considered significant. (29)

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* This was later formally bounded and evaluated as the Statfjord field.

- July-August: Extensive parlimentary and public debates on exploitation vis a vis conservation. Should exploitation result in lower taxes, GNP no-growth policy, build-up in foreign exchange. Ship and big builders making greatest profits, but economy cannot stand extensive financial flooding. London Economist referred to Norway as the "Sheikhs of the North."(30)

- August: Field discovered by Mobil Group (Statfjord) estimated at 2 billion bbl oil and 1.76 trillion cu ft gas. Larger than Ekofisk. Problem of an "embarrassment of riches" apparent. Out-of-country investments sought.(31)

- September: The Research Vessel "Glomar Challenger" operating on the Deep Sea Drilling Program of the U.S. National Science Foundation, found hydrocarbon indications in the vicinity of the Voring Plateau, well north of 62° and at water depths of 3,000-4,500 ft. The activity was core-sampling for research purposes, and not part of a search for resources. The results were embarrassing to all concerned, and has driven Norway to assert a "Continental Shelf" position in the area, since "drilling is technically possible" at such depths. The "Glomar Challenger's" action in pulling a core sample was a far cry from the technical difficulties of drilling a producing well, setting casing, establishing a production platform, etc. at such depths, but a geopolitical storm was brewing by mid-October 1974. North Norway demanded that drilling north of 62° go ahead, looking to the prosperity of previously-depressed Scotland under the impact of the U.K. North Sea oil boom.(32)

— October: The Norwegian Minister of Industry told the Storting (Parliament) in late October that the "scientists aboard the U.S. 'Glomar Challenger' acted irresponsibly in drilling a well (sic) near the Island of Jan Mayen on the Voring Plateau without permission from the Norwegian Government." The Minister stated that he will take up the matter with those responsible for the research expedition (Scripps Institute and the NSF Deep Sea Drilling Program). The Norwegian authorities were particularly upset since the Glomar Challenger was a core-sampling research vessel that did not have equipment to prevent a blowout.(14)

The potential impact of this incident on International Law and the Laws of the Seabed was serious. A Storting Act of 1963, based on the Geneva Convention of 1958 (not the 1964 Protocol cited earlier) extended Norwegian jurisdiction "as far out as the sea depth makes it possible to exploit natural resources."(33) At the time of the Act, it was considerably more difficult to drill nearly 1400' in nearly 4000' of water, and such a concept was considered academic. However, in view of definite hydrocarbon shows (a "teacup" according to NSF) Norway now claimed the disputed hole, and the rights to permits and leasing.

— November: North Norway, a depressed economy, suffering inflation, and high taxation associated with extensive government social services, demanded that leasing and exploration proceed north of 62° area. Possibly yielding to such pressures, Norway announced additional leasing along almost the entire median line north of Ekofisk plus two blocks on the 62d parallel. Geophysical activities increased in the north of 62° sector, and it was doubtful if Norway would be able to resist pressures for additional exploratory wells.(34)

Norway's North Sea Reserves

Since the 1970 discovery of Ekofisk, initiating the North Sea oil boom, Norway has been considered to be the "Saudi Arabia of the North." The recent spectacular discovery in the Statfjord Fields has enhanced this analogy. Before the Statfjord finds, Norway's North Sea petroleum reserves were estimated at ten billion barrels, and natural gas reserves at 23 trillion cu ft. Statfjord's finds have added an additional 2 billion barrels and 1.76 trillion cu ft of gas at a minimum. Massive quantities of gas associated with oil development at Ekofisk will soon be piped to Emden, W. Germany, and gas from Frigg Fields in the North will go to Scotland. Norway apparently does not envision any insurmountable engineering problems in constructing a pipeline from the shallower areas of the North Sea across the Norwegian Trench, but given Norway's industrial base, considers such an expenditure unwarranted in the immediate future. A small-diameter gas pipeline is under active consideration from the Frigg Field to a terminal at Karmoy, at the northern entrance of the Stavangerfjord.[(16)] Since pipelines are not yet operational, oil transportation has been by tanker from offshore storage facilities, the most notable of which was the 1 million barrel concrete tank which was floated to the Ekofisk Field and sunk into position. Bad weather has made tanker loading difficult, and production from Ekofisk was curtailed in 1973 and early 1974. Since the Ekofisk-Emden pipeline was not in service, gas from Ekofisk had to be re-injected. There were serious technical difficulties, also impacting production, during the same period.[(26)] The status of Norwegian North Sea oil and gas development and reserves at the end of 1974 was as follows:

- One major producing field, Ekofisk, which with satellite fields was estimated to possess more than

2.3 billion bbl of reserves and was producing 50,000 bbl/day. Limitations have been weather and gas injection problems.

- One new giant field, Statfjord, defined with estimates in excess of 2 billion bbl crude and 1.76 trillion cu ft gas, established on the basis of only 3 exploratory wells.

- Expansion of the Heimdahl exploration and assessment activity into what is believed to be a commercial field.

- A general holdback on additional developments, pending pipeline and terminal facility developments in the U.K. and Germany.

With "ultimate reserves" estimated in 1974 at 10 billion bbl, 5 billion bbl were brought to the status of "proved reserves" by the end of 1974. 1974 gas reserves, with the Statfjord discovery, are estimated in excess of 24 trillion cu ft.

Norway and the North Sea Oil and Gas Industry

Norway is achieving spectacular industrial progress in the oil and gas industry area. The most spectacular construction activity to date was the fabrication at Stavanger of the Ekofisk million-barrel, reinforced-concrete storage tank and gas injection platform. The deep harbors and fjords of coastal Norway have proved to be ideal for the fabrication of construction platforms, semi-submersible drilling vessels, and the new "Condeep" subsurface storage tank and production platform combination. Most orders are for planned operation in U.K. waters. Only two harbors suited for the fabrication of such structures are available, both in Scotland, where deep water fjord-like harbors exist. Early in 1975 government nationalization plans for these facilities were announced — new orders have gone to Norway.

Norway has designed a semi-submersible, the "Aker H-3" (see Section 2, Figure 2.4), which has proved to be a popular design, well suited for the North Sea. Twenty-five of these craft are on order in shipyards throughout Norway, and initially were placed on the market at $25,000,000. From workboats to offshore platforms, Norway has undoubtedly made significant gains in the economic sector, even though she is maintaining a modest pace in developing North Sea oil and gas. At the same time, the minority Labour government finds itself under conflicting pressures from all sides, a situation not dissimilar to the "pro-growth" and "no-growth" philosophies impacting suburban United States, but on a far vaster scale. The situation is recapitulated well in the following editorial, from The Economist of September 7, 1974[35] entitled "What oil did for Norway," and summarized by the sub-head "Some Norwegian politicians are profoundly disturbed at the effect that oil is having on their country. The role of sheikhs of the north sits uncomfortably on them."

> Norway can afford to be more choosy about its oil than Britain can. It has one of the highest living standards in Europe, including welfare at Swedish levels. Yet the minority Labour government may even wish sometimes that North Sea oil had never been discovered. It is dithering, at a time of rampant inflation, over how much further to carry its intervention in industry, about how to deal with rising middle-class discontent over taxation, and about how to cope with the country's mood of growing insularity.
>
> The outward signs of success are all there: an economy expected to grow 5 per cent this year and industry working flat out. Labour is increasingly scarce. Hydroelectricity, which accounts for half the country's energy, is exceptionally cheap. By next year Norway expects to be a net exporter of oil. Foreign exchange reserves are at a record, and the krone has been upvalued twice in 18 months.

So the government has none of Britain's nightmares about unemployment and the balance of payments. But it, too, is faced with an increasingly demanding electorate. The Norwegians enjoy much higher living standards than British workers. But price rises have become disturbing. Income tax is sharply progressive and, because of inflation, catches more and more semi-skilled workers — so discouraging overtime. Labour costs have become so high that restaurants are a luxury and do-it-yourself is an economic necessity. Vat rates are among the highest in Europe and customs duties can be fierce. But, despite growing discontent with tax rates, there are equally growing demands for better welfare.

So in Norway some members of the Labour party look to North Sea oil as the miraculous solution to their problems and the means of their eventual re-election. Very few concessions have yet been awarded in the Norwegian sector and exploration has been much less intense than in British waters. But Norway is already receiving North Sea crude and by the 1980s expects to be earning at least £1.2 billion from oil because of its increasingly tough participation and tax policies. With another giant find confirmed last week at Statfjord, opposite the Brent field, the prospects look brighter than ever.

Norwegian industry has been cashing in on the new business, showing greater initiative than most British companies. Norwegian shipowners, who are now running into some difficulties after last year's boom, have been ordering drilling rigs and supply ships. Norwegian shipyards have switched increasingly to building drilling rigs and production platforms. The big Aker group has won orders for 26 rigs. Norwegian Contractors has developed the Condeep concrete production platform, and a third group has just launched a concrete drilling rig, Condrill. Norwegian engineering industries have seen the possibilities of working in the offshore market and the Kvaerner group has gained an important lead in the liquid gas transport business. In addition, Norway will now be developing a new business, petrochemicals. According to government estimates, the offshore oil business should bring Norwegian companies over £220m worth of work this year, of which £70m will be exports, growing to £400m by 1980, of which half will by then be exports.

But there are problems. The economy cannot absorb such a sharp increase in revenues, extensive oil exploration cannot be carried out simultaneously in both the North Sea and the north of Norway and Norwegian industry has not got the manpower to cope with the new demands being placed on it.

In theory, the government does not need to spend its income in Norway. It could pay back its £1 billion in foreign debts. It could buy out foreign participation in Norwegian companies or invest overseas in oil or other sectors — and so prevent oil revenues spilling over into the domestic economy and increasing inflationary pressures. But this will not produce the socialist paradise. Norway could import foreign labour, but the Norwegians have no intention of complicating their lives in that way. Norway could use up the oil money by increasing imports or reducing exports — a possible solution, but one that has harmful long-term implications for domestic industry. According to studies made by the government, the economy will not be able to absorb much more than £500m a year in 1980 out of the £1.2 billion revenue anticipated. The government would hope to use that money in reducing taxation, stepping up public and private investment and acquiring control of key sectors of the economy.

What really worries the Norwegians is the impact of oil on their traditional way of life. In Scotland the fishermen and certain local communities have grumbled about the new oil industry, but in general the extra work and revenues are welcomed. In Norway there is almost universal concern that the oil boom could destroy the fragile social structure that has survived the second world war and subsequent prosperity. Although farming, fishing and some other industries have become increasingly uneconomic in Norway, the Norwegians are ready to subsidise them to keep the remoter parts of the country populated. The Norwegians thought the common market would destroy these traditional activities and voted against it. Today they feel the same way about oil.

It may bring jobs to the less-developed regions at the price of depopulating other parts as local farmers and fishermen opt for the higher wages offered by the oil business. The industry itself may require only an additional 10,000 men by 1980, but ancillary services will absorb many more. In addition, an increasing number of noisy minority groups see no need for further industrialisation, are concerned about environmental hazards and dangers for fishing, and demand more say for local interests to halt centralisation and red tape.

With so much at stake and so little to gain, the Norwegians are not too concerned about the value of their oil to other countries. They have definite reservations about oil-sharing schemes and have imposed tough terms on the oil companies. It is largely because of Britain's intense exploitation of its own waters that the Norwegians are obliged to exploit theirs. In the current round of oil licences only blocks that border on the British sector will be allocated — otherwise pumps on the British side will suck the Norwegian oil across the British sector.

The statement that "It is largely because of Britain's intense exploitation of its own waters that the Norwegians are obliged to exploit theirs" bears comment. Most of the prolific oil-bearing structures are literally on the median line, and intense British exploitation of the "Brent Blocks" led to the recent Statfjord discoveries. Britain intends to go "all out" on the Brent developments, and could completely obviate the conservation and slow-development policies of Norway by literally pumping the field to a non-commercial level before Norway decides to bring "her half" into production. In such cases the geological facts of life may determine political and economic decisions.

This article from The Economist was obviously written before the Statfjord discovery, and therefore becomes more germane since Norway has a "super-Ekofisk" in her north central waters.

An increasingly harrassed Europe looked to such developments as potential economic salvation from complete dependence upon OPEC countries. When Norway announced that she did not intend (immediately at least) to proceed with the development of Statfjord, the article below appeared in the Oil and Gas Journal for September 23 (36) in the "Watching the World" column by Frank J. Gardner, datelined London and sub-titled "What now Oslo?" It not only is significant, but also represents the current geopolitical thinking in the EEC vis a vis Norwegian North Sea oil.

What now Oslo?

The term "embarrassment of riches" is a cliche, but it's a situation most people would love to find themselves in.

Not so the Norwegians. For months now, they've been telling the world that they're going to restrict offshore oil production and retard exploration by holding new acreage blocks off the market. The embarrassment was Ekofisk and its satellite fields in the North Sea.

The Ekofisk complex is destined to bring about 1 million b/d onto world oil markets when it's in full production. That's about six times Norway's daily oil consumption.

The Norwegian economy, the government has said, simply can't absorb all the income that Ekofisk could generate.

But if Ekofisk was an embarrassment of riches, Norway now faces sheer mortification. For along the median line with British waters, the Mobil group has uncorked the biggest field yet found anywhere in the North Sea — a field capable of producing as much oil as the entire Ekofisk complex.

There was a time when no oil company would dare think of announcing a field reserve estimate until at least 10 or 12 wells had been sunk on a structure. But times (and techniques) have changed.

Norway's industry ministry, on Aug. 29, announced that the new Statfjord field in Norwegian Blocks 33/9 and 33/12 holds 2 billion bbl of oil and 1.76 trillion cu ft of gas — and that after only three wells.

By the side of Statfjord, Ekofisk field, with only 1.12 billion bbl of proved reserves, became overshadowed overnight.

WHAT NOW, Norway? With West Europe thirsty for crude oil and almost totally at the mercy of the OPEC cartel, can Oslo in good conscience withhold 2 billion bbl and more off the world market?

Not likely. The western world is fast losing patience with OPEC and its consistent price increases. It must turn to every possible non-OPEC source in its search for cheaper oil. And it's willing to help Norway overcome its financial fears.

No one can force the Norwegians to open the valves at Statfjord or Ekofisk. But there are other ways to funnel her oil income away from the source.

Surely the sophisticated financial talents of Europe and America can devise avenues of foreign investment that would skirt the inflation and related excess-revenue problems that haunt Oslo today.

Another fear, this time on the part of the oil companies, is that such unexpected success in the North Sea could lead the Norwegians to halt all block awards — even those that have been on the brink of announcement for more than a year.

It's a dilemma that almost any other western country would be happy to endure.

Norway appears to have recognized the impact of this position, and has relented on the minimal development approach to some extent with the announcement of lease sales opposite the median line with the U.K. and along the 62d parallel.

Norway and the International Energy Program

The Washington Energy Conference held in the wake of the Arab Embargo of 1973/74 was structured so that no one country would be heavily impacted by selective embargo procedures, and would, in short, share limited resources in the case of the renewal of such an embargo. In the fall of 1974, Norway decided not to participate in the plan, anticipating self-sufficiency in the late 1970s. From the Norwegian point of view, the move made considerable sense as the treaty stipulated:

- All participating countries must maintain emergency stocks for at least 60 days consumption with no net imports. Stocks to be increased to 90 days supply as soon as practicable.
- In the event of embargo of either selective or general nature, each member country to practice specific energy demand reduction measures
- When shortfall reaches 12%, each country to reduce demand by 10%, whether directly impacted or not.

Norway felt that these terms (highly summarized from a very complex document) were unacceptable, and as a major potential European oil-producing state, "opted out" of the government. According to the London Times of November 4, 1974, the U.K. is considering a similar step.[37]

A.2.8 Netherlands

The Netherlands is unique among the North Sea coastal countries because its major energy reserves lie onshore. Small quantities of oil were discovered in World War II, and by the mid-1950s five small fields were in production. One cluster was located

along the West German border, the other in the vicinity of the Hague. From a high of 125,000 bbl/day, production (1974) slumped to less than 26,000 bbl/day, although secondary recovery methods are being contemplated if North Sea oil development and delivery systems continue to slip.[4]

The major energy resource of the Netherlands is the Gronigen gas field, the largest in Europe and possessing 70 trillion cu ft of reserves. An extensive network of pipelines extends from Gronigen throughout northern Europe, and production of 2.53 trillion cu ft/year is currently established. Approximately 40 percent is exported to Belgium, West Germany, and France — and exports are expected to increase as an integrated European Pipeline network extends to Switzerland, Italy, and the southern portion of West Germany.

The increase in exports will be more than compensated by the development of the Placid offshore gas field in the North Sea, Netherlands sector. The Placid field is in the process of being linked to the Gronigen area by a 99 mile 36" pipeline that should transport 580 billion cu ft of gas per day into the Gronigen/Netherlands network. In the meanwhile, additional gas finds have been made in Netherlands waters, and the estimate of 6 trillion cu ft currently made for the Placid (L/10) field is expected to escalate.[4]

During the 1973/1974 embargo, the Netherlands, although a selected target for embargo, coped extremely well by using a combination of geography and determination. Although the Gronigen fields were not used as a "hostage" the threat was present, and those EEC nations who were dependent upon the natural gas of the Netherlands tried to see that sufficient oil reached the Netherlands to keep her industry operating. The Netherlands, however, did have to

restrict civil transportation. Crude entering Western Europe was both offloaded and refined in the Europort complex at Rotterdam, which permitted some discretionary diversion to Netherlands channels without a blatant violation of the boycott (which would have impacted those countries of the EEC who were not involved).[38]

In addition to membership in the International Energy Program, mentioned in the Norway section (Section A.2.7) of this Appendix, the Netherlands is working toward energy independence by converting oil consuming facilities (power plants and industries) to domestic gas. At this writing, gas supplies approximately 45 percent of the industrial, commercial, and residential requirements of the Netherlands.[39] The current goal is to raise the contribution to 65 percent, and, if feasible, to phase in nuclear power so that gas and electricity would carry the major components of all industry except petrochemicals and transportation. In the meanwhile, exploration for additional gas (promising) and additional oil (unpromising) continues.

A.2.9 Denmark

Denmark's position in the context of North Sea oil and gas is somewhat ironic. Oil, in commercial quantities, was first discovered in the Dan fields in the Denmark sector about a year before the highly publicized Ekofisk discoveries. Based on this discovery reserves were estimated as approximately 250 million bbls and 1.8 trillion cu ft of gas.[4] Four wells have been placed in production at Dan, at a rate of 3000 bbl/day. (For contrast one test well at Statfjord produced 10,500 bbl/day through a 1-inch choke.) Transport, weather permitting, is by tanker — no pipelines are planned unless a greater volume at a concentrated source (e.g., Ekofisk)

is developed. In 1973 the consortium drilled four dry holes; it plans to concentrate its 1975 drilling as step-outs from Dan and hopes to double the production of the field. Additional new structures are being wildcatted based on updated seismic information.[4]

None of the gas shows in the Danish sector have proved to be worth commercial exploitation, but the 1974/75 drilling program, again based on seismic updates, is re-investigating other areas of promise. With a small industrial base, Denmark had hoped to relieve locally high energy prices and dependence upon imported sources by aggressive development of Danish North Sea waters, but she has been less than successful. Still, seismic shows are favorable, and if the ever-escalating costs of exploration and development can be tolerated, Denmark may yet attain a higher measure of energy self-sufficiency. Natural gas is sought in particular, as Ekofisk to the north and the Netherlands North Sea to the south both have shown excellent potential. Denmark's exploration program has been small, yet the area of her sector is approximately equal to that of the Netherlands. As the Oil and Gas Journal recently stated, "So far, the Danes have caught only minnows in the North Sea, but if there are whales there, surely that $39 million (1974 exploration budget) should find one."[40] They did not. Late in 1974, in the face of low potential rate of return, Gulf Oil withdrew from DUC. Gulf's 30 percent has been divided among the other Consortium participants who will continue exploration.

A.2.10 Federal Republic of Germany

West Germany has no producing facilities in its North Sea sector, and over the past five years has drilled 11 dry holes.[4]

Seismic exploration continues, and the hope is that some marginal gas wells adjacent to the Dutch sector may be developed into producing facilities. West Germany currently gets gas from Gronigen and will shortly receive gas from Placid in the Netherlands sector, and Ekofisk in the Norwegian sector totaling 800 million cu ft per day by 1976 when both pipelines are expected to be completed. No North Sea oil pipelines to West Germany are under active consideration. Supply from the North Sea will therefore fall far short of demand, and despite marginally favorable geology the prospects of a major field on the dimensions of Ekofisk, Forties, or Brent are slight. Because of the proximity to Gronigen and the increase of a natural gas based economy, plans for expanded LNG imports are being implemented.[39] It must be noted, however, that Germany produces most of the coal of the EEC, and so there is room for energy balance and barter if required.

A.2.11 Additional European Oil and Gas Sources

Not all of the petroliferous areas of Europe lie in the North Sea or along its coast. For the past several decades, modest quantities of oil and gas have been found and developed in inland fields, of which West Germany has the largest production, and Italy the largest reserves. In February 1975, Italy announced a highly promising find in very deep wells in the Po Valley area[41] which may help that country in its untennable foreign exchange problem in the purchase of OPEC crude. In Tables A.3 and A.4, oil and gas reserves and production of various Western European countries are presented. Countries such as Spain and Austria have modest oil and gas assets that can be developed and, if enhanced recovery technologies are applicable, assist those nations in independence from OPEC and its associated pricing structure.[4]

Table A.3. Domestic Oil Production and Projections for 1980-1985

Country	Production (1000 bbl/day)		Expected North Sea	Consolidated Domestic Production (1000 bbl/day)		Estimated Reserves (million bbl)
	Current Domestic	Current North Sea		1980	1985	
Austria	47.059	0.0	0.0	34.5	30.0	160.0
Belgium/Lux.	0.0	0.0	Approx. 30% Ekofisk Prod.	0.0	0.0	0.0
Denmark	0.0	4.0	8.0 (Series of dry holes, 1973/74)	8.0	9.0	248.5 (North Sea sector)
France	20.170	0.0	0.0	18.0	17.0	142.0
W. Germany	117.595	0.0	Unknown (no rigs working)	81.0	66.0	550.0
Italy	18.328	0.0	0.0	12.0	10.0***	750.0***
Netherlands	27.391	0.0	Unknown (one small field not developed — emphasis on goal)	24.0	21.0*	251.0 (North Sea sector not included)
Norway	0.0	30.0	>1500.0 (Depending on rate of development and export)	200.0	500.0	1000.0 (North Sea sector)
Spain	37.430	0.0	0.0	45.0****	50.0	293.0
United Kingdom	1.5	40.0	>3000.0 (Including Norwegian sector production)	480.0	600.0	1300.0 (Primarily North Sea sector)

* Secondary and tertiary recovery systems may reactivate shut-in or low-level producing wells if world price is high enough

** Germany has not pursued an active exploration-drilling program, but has done extensive seismic work in North Sea. Reserves cited do not include North Sea potential, not yet established, but are limited to inland fields.

*** New offshore discoveries in Adriatic look promising. Po valley 1975 discoveries not included.

****New Mediterranean fields established. Initial wells working. Greater activity expected in next decade.

Table A.4. Domestic Natural Gas Production and Projections for 1980-1985

Country*	Production (million cubic feet per day**)		Expected North Sea	Consolidated Domestic Production (Includes direct supply from North Sea)		Estimated Reserves (billion cu ft)
	Current Domestic	Current North Sea		1980	1985	
Austria	191.7	-0-	-0-	148.3	114.8	None
Belgium	-0-	-0-	Will share in Ekofisk at approx. 1, 100	None directly, except third country		None
Denmark	-0-	-0-	Unknown, generally favorable structures	Unknown pending further North Sea expl.		1, 800 (North Sea sector)
France**	715.0	-0-	Indirect through third country imports	946.0	946.0	6, 500
W. Germany	1, 650.0	-0-	800 from Norwegian and Netherlands fields in North Sea	2, 143.3 + 200 N/S?	1, 840.0 + 400 N/S?	12, 308
Italy	1, 400.0	-0-	North Sea plus Gronigen indirectly	1, 434.0	1, 487.0	5, 300
Netherlands	6, 900.0	-0-	600 firm plus development of adjacent structures	8, 000.0	3, 500.0	94, 800
Norway	-0-	-0-	2, 600 plus other discoveries not yet in development stage	2, 600.0 + ??	3, 200.0 + ??	23, 000 + extensive N/S not proven
Spain	-0-	-0-	-0-	0 (only if gas is found in commercial quantities in Mediterranean oil exploration)		500
United Kingdom	Minimal	3, 300	4, 800 + imports from Norwegian sector and new discoveries	5, 200.0+	5, 200.0+	50, 000

* Natural gas energy content: France, $3.25 \cdot 10^5$ kcal/ft^3
Italy, $3.21 \cdot 10^5$ kcal/ft^3
Others, $2.96 \cdot 10^5$ kcal/ft^3

**Ref.: Commission of the European Community, "Medium-term Prospects and Guidelines in the Community Gas Sector," Brussels, 1972.[14] See also text comments.

Spain is successfully developing offshore wells in the Mediterranean, as is Italy in the Adriatic. A new vehicle for confrontation between Greece and Turkey could evolve in applying the Continental Shelf doctrine to the Agean Islands, in which offshore exploration is currently in progress. A minor confrontation was reported in the Economist[28] in an article "Does the Oil go with the Islands?"

It may be noted in Table A. 3 that domestic oil production of France is gradually declining, as would be expected in small fields without application of enhanced recovery techniques. However, gas production (Table A. 4) from small fields is expected to gain.[39] A parallel cannot be made with the U. S., in which domestic gas production has declined from small fields, since (a) large-scale national pipeline networks do not exist, and (b) U. S. regulatory procedures, particularly in interstate gas, not only discourage new exploration but even have caused the shutting-in of some producing wells.

A major energy source potential for Italy, albeit OPEC, is the very active concept of a Trans-Mediterranean Pipeline, via Sicily and the Straits of Messina; it would carry North African gas to the European mainland. It would be an extremely costly venture that must be weighed against the costs of additional LNG terminal and gasification installations. Italy's current economic status mitigates against early initiation of the project, but the implications are significant. West Germany's fields are still producing at a satisfactory rate, and little or no enhanced recovery techniques have been applied. In view of the lack of success of the FRG in the North Sea, a greater share of W. Germany's inland reserves may be exploited. In the context of W. Germany's industrial base, her inland reserves are minuscule; however, with greater exploitation of coal and current OPEC prices, they are assuming more than marginal significance.

A.3 COAL RESOURCES OF EUROPE

A.3.1 General

Coal, Europe's most durable and long-lasting fossil fuel, is widely distributed and has been the backbone of European industry since the Industrial Revolution. It was in household use in England in the nineth century, and by the thirteenth century was an active component of the local national economies. The invention of the steam engine stimulated active coal mining, as industrial manpower was replaced by machinery. Smelting and metal working had gone on for literally thousands of years, but the forests of Europe were being depleted. Then it was discovered that anthracite was an excellent fuel for smelting and this provided another, self-perpetuating stimulation to the mining and exploitation of coal. The metallurgical industry then determined that coke, made from bituminous coal, was a superior metallurgical fuel, and the industry again expanded in what appeared to be an ever-increasing manner. Gas, made from coke, was used not only in the industrial context, but as a source of domestic and industrial heat, and "town gas" is still a significant European energy source in local areas. Only after World War II did the use of coal in Europe, particularly in industry, begin to give way to a more efficient and less expensive but far less plentiful rival — oil, and later, natural gas. Europe, like Japan a decade later, began to gradually shift away from plentiful inexpensive domestic coal (although tremendous quantities of metallurgical coal were imported from the United States) to oil from the Middle East. Mining and production of coal began to decline at an ever-increasing rate. Even with the embargo of 1973/74, and the increase in the price of imported Middle-Eastern oil, it is unlikely that coal will

ever regain its pre-eminence in Europe. Oil and gas for transportation and industry will continue to be imported, and it is planned that nuclear power will be the primary component of electric power generation, although Germany and the U. K. have taken strong stances against these trends.

These decisions were not necessarily capricious, since many of the mines of Europe were playing out, were obsolete, were very thin-seamed, and labor intensive. When competing fuels became available, such alternatives were most attractive. The use of coal for residential heating was already on the decline, particularly in the U. K. because of air pollution problems typified by the pre-war "London Pea Soup Fogs" now a rarity. Fireplace burning of coal was legally forbidden in the 1950s and the incidence of such fogs dropped sharply.

A second major cause of the decline of coal mining in continental Europe was a vanishing labor force. The post-war industrialization of Europe, particularly in the manufacturing industries absorbed most of the labor force who might, a generation earlier, have gone into coal mining. Many manufacturing industries became labor deficient in the 1960s and imported laborers were absorbed by the manufacturing and service industries, not by mining. In the meanwhile the indigenous mining force diminished through attrition, as the elders left the pits, and the younger generation opted for a more pleasant means of livelihood. In the late 1960s and early 1970s, the decline in mining, particularly on the continent, steepened.

The decline in production was also caused by lessened demand. The residential market for coal declined, as mentioned.

Commercial buildings, formerly heated by coal, switched either to fuel oil or to town gas produced from coking coal. A subsequent change to natural gas was simple. Only in the U.K. did a large-scale, relatively viable (albeit nationalized) coal mining industry continue to exist. Elsewhere in Europe, the only major markets for coal were the metallurgical and electric power generation industries. Coal mining was essentially limited to supporting those industries where either no substitute was possible as in the case of iron and steel, or conversion was technically or economically infeasible as in the case of many major power plants.

Thus a stable market base for coal was established, but one that was unlikely to grow, and (pre-embargo) would probably shrink through attrition. Imported coal was expected to make up the difference between domestic supply and demand.

A.3.2 European Coal and the Energy Crisis

The desirability of Europe lessening dependence upon OPEC by carrying out a major coal conversion or switching program can be compared to that mandated by the U.S. "Energy Supply and Environmental Coordination Act of 1974" (PL 93-319). This act, brought on by the 1973 embargo and administered by the Federal Energy Administration, required that "... any power plant in the early planning process (other than a combustion gas turbine or combined cycle unit) be designed and constructed so as to use coal as its primary energy source...." The act further directs the retrofiting of formerly coal-burning plants that had converted to an alternative fuel, under criteria too numerous to be included herein.

The EEC nations are in a different position. Although their reserves are extensive, their coal industry has been declining for a decade or more. The mining labor force is depleted. The geology and structure of many mines makes large-scale, non-labor-intensive mining technologically difficult and, in many cases, economically infeasible. Only by exchanging dependence on one imported substance, Middle Eastern oil, to another, U.S., Canadian, Polish, U.S.S.R. and Australian coal, could a large-scale conversion (of the scope as that proposed for the U.S. under PL 93-319) be implemented. Such a conversion, with both North Sea oil and gas and nuclear power on the horizon, and coal increasing in price, seems exceedingly unlikely.

A.3.3 Overview of the Reserves of the Community

Coal has been used in Europe for almost a thousand years; the geology of Europe has been studied for well over a hundred years; therefore estimates of the total reserves of coal on the continent and the U.K. have not changed much over the past decades. What has changed and continues to change are the estimates of "economically recoverable" coal. The situation is similar to that of oil and gas "reserves" discussed earlier. When coal was cheap and oil expensive, economically recoverable reserves of coal were high. As miner's wages increased, particularly in the U.K., and as competing fuels became more attractive, economically recoverable reserves dropped. In the 1974-1975 economy, competing fuels, primarily OPEC oil, made the comparative price of coal considerably more attractive. The price of coal itself has escalated on the world market – dependence on imported coal is, therefore, a less attractive alternative, given its price and the drain on foreign exchange. A fresh look is being given to "economically recoverable

reserves" particularly in the U.K. and West Germany. The general datum for economically recoverable reserves has been pit-mining to the 1200 meter level. Although considerable coal exists to the 2000 meter level, mining below the 1200 meter level is considerably more expensive on a capital and labor basis. Should the economic and geopolitical situation so justify, however, economically recoverable reserves may be expanded to include the 2000 meter depth which, given advances in automated mining technology currently under examination in the U.S. and W. Germany, may happen.

A.3.4 Production and Reserves (Table A.5)

When examining the status of coal in Western Europe, it must be remembered that a large quantity of coal does not enter the energy-production cycle at all, but is directly consumed in the iron and steel industry. It must also be pointed out that some coal "lives two lives," first by being transformed into coke for the iron and steel industry, and secondly by producing gas. The gas may be either integrated in industrial processors, or may be shared as "town gas" by consumers. Data as to the distribution patterns of European coal are often lacking. Thus coal for the iron and steel industry becomes homogenized with coal for energy uses. Subbituminous and lignite are also often blurred in their allocation to specific demand functions, and high btu bituminous and anthracite coals may also be mixed statistically. In general, the major component of coal reserves is referred to in most European and U.N. publications as "hard coal," corresponding to both bituminous and anthracites rated in the U.S. at 13,100 btu/lb. European statistics have standardized on the 7000 kcal/kg for their "hard coal" and make little differentiation, statistically, between anthracite and bituminous

Table A.5. Domestic Coal Production and Projections for 1980-1985

Country	1973 Production of Both Hard and Soft Coal (million metric tons)		Economically Recoverable Reserves (million metric tons)		Estimated Future Production (million metric tons)		Remarks
	Anth. & Bit.	Sub-bit. & Lig.*	Hard Coal	Soft Coal	1980	1985	
Austria	Negligible		---	64	Continued Negligible		Historical decline expected to continue unless price of oil becomes completely untenable, and exploitation of reserves becomes an attractive option.
Belgium/Lux.	8.8	---	253	---	6.8	5.4	Historical decline expected to continue but rate of decline will decrease. Natural gas expected to continue to replace coal in industrial and commercial use.
France	25.7	0.9	443	15	28.0	30.0	France is concentrating on more productive mines, with a decreased labor force. Energy problems, and no North Sea resources should encourage the achievement of government-stated goals.
W. Germany	97.3	36.0	30,000	9,571	95.0	95.0	Current plans are to stabilize production at 95 million ton level, with the closing of inefficient mines. New expansion of facilities will be required to increase production significantly, as subsidies are currently required. Oil prices may force a decision in 1975.
Greece	Negligible		---	150	Negligible		New offshore oil finds further tend to negate role of coal.
Italy	0.1	0.4	---	33	Negligible		Extensive government support required which is not foreseen with current oil/economic crisis.
Netherlands	1.7	---	1,843	---	1.0	0.5	Government plans to close all mines and use extensive natural gas reserves.
Spain	9.9	(3.1)	453	1,190	8.0	7.0	A relatively "poor" country with a large labor force, Spain may well keep a coal industry as a viable energy option.
United Kingdom	129.9	---	3,870	---	130.0	130.0	Objective is to "stabilize" in the face of increasing demands and the exhausting of a large number of marginal mines. Estimates are based on a "120-150" million ton domestic demand by 1985, and realistically considered in the context of strikes, economic problems, etc. that traditionally cause failure to meet planned goals.

*Hard coal equivalent

(which may have overlapping btu values, but differ in ash, particulate, and moisture content). The other major category used in European data is "brown coal" which covers the entire range of the lignites.

A.3.5 Production through 1972

The United Nations and the EEC compiled extensive coal and energy statistics through 1972. The expansion from "the six" to "the nine" with the addition of the U.K., Ireland, and Denmark has only been impacted, in the coal area, by the substantial addition of the U.K.; Ireland (only 3 mines) produced only 100,000 tons of coal in 1971 and Denmark, none. The data originally assembled through 1972 for the EEC(6) will therefore be valid for this section. Data for 1960-1968 were acquired from the USDI, Bureau of Mines document "United States Coals in World Markets."[42] Updates on U.N. and EEC data were informally confirmed by the author of the document in 1974.

A.3.6 Belgium/Luxembourg

General

Belgium has been phasing out, for more than a decade, uneconomic mines. Difficult mine structure and geology, combined with a very labor-intensive mining economy, limited the use of mining machinery to larger and more favorably-configured mines. Thus mine output dropped steadily from approximately 30,000,000 metric tons in the 1950s to the 20,000,000 ton level in the 1960s to a little more than 10,000,000 tons in 1972, and 8.8 million in 1973.

Belgium has two major coal field areas, the Sud coal field, where production is continually declining, and the Campine fields, in which production has generally stabilized. Coking coals are the main product of the Campine fields, located in northwest Belgium, sharing the same general horizons as adjacent fields in the Netherlands and Germany. Production in the adjacent Sud fields is approximately half of that of the Campine fields. Two collieries have been shut in the Sud fields, and an approximately 7 percent drop in manpower is reported. Fifteen collieries (1972 data) operated in the Sud and only five in the Campine, but those in the Sud were constantly losing money, and were characterized by a lower output per man than those in the Campine. Although neither field was economical, the 1972 loss in the Sud was 5 percent greater than that in the Campine. Both fields were affected by an ever-increasing gap between production costs and income, and high wage costs resulting from new social welfare programs. Tieing wages to the consumer price index has caused a direct impact on production costs by the worldwide inflation, and colliery losses are being subsidized by the Belgian Government at an ever-increasing rate.

Outlook

Much of the closing of collieries and phasing out of low-production mines has been caused by a decline in the coal-consuming sector. Thus lower production nationally did not cause, through 1972, a decline in surplus stocks. Despite the 1973 oil embargo and the current high prices of oil (but not natural gas from nearby Gronigen in the Netherlands), a continual decline is expected in an industry in which working conditions are poor and dangerous, output is low, and wages, tied to "escalator clauses," are constantly increasing. Even though Belgium does not have a leasing program in

the North Sea, it stands to benefit from North Sea oil prices that are expected to be less than the $12-13/bbl charged by OPEC. The decline in Belgium's high-cost and relatively inefficient coal industry is not likely to be lessened by either high oil prices or high coal prices, as costs of production tied to inflation, would also rise.

A.3.7 France

General

France has adequate and extensive supplies of coal, but lacks high quality coking coals required by the metallurgical industry. Lower qualities of coal are as expensive, or possibly even more expensive to mine than high quality coal, thus the economic trade-offs of developing France's sub-bituminous and lignite reserves, plus a large number of small uneconomical mines have kept France as a net importer of coal, primarily from West Germany, Poland and the U.S. France's production of coal has, like the rest of Western Europe's, sharply declined since 1960. Since, in some areas lignite is used in French electric power stations, lignite is included in the French production presented in Table A.6, below. Sample years are presented for comparison.[42]

Outlook

In 1973 President Messmer, in the dedication of a large coal-burning plant in France announced that "this was to be the last fossil-fuel plant in France" and that France was turning to a "completely atomic" and "completely electric" economy.[43] This policy had been decided upon before the oil embargo and the rise in Middle-Eastern oil prices, but was announced in October 1973 in a most

Table A.6. Coal Production in France

Year	Production (million metric tons) Hard	Lignite	Remarks
1960	56.0	2.3	Peak year of record
1963	47.8	2.5	Extensive miner's strike
1965	51.4	2.7	Marginal mines begin to be phased out
1966	50.3	2.6	Effects of phaseout policy
1970	37.3	2.8	Switchovers to oil and gas
1971	33.0	2.8	Last year complete record
1972	29.7	3.0	Fell below governmental goals and predictions
1973	25.7	2.7	Stabilization objective put forward by Pompidou Government

timely fashion.[44] This policy dictates a continuing decline for the French coal industry with the exception of a base economy involving the requirements of the metallurgical industries and the requirements for power stations and industry. With the franc/dollar ratio in the favor of the former, import of American coal (even as opposed to West German coal) seems to be a likely and attractive alternative. France, like the rest of Western Europe is faced with an obsolescent mining industry and an aging work force. Few young people enter the mining industry (although a serious depression could change this situation), and the outlook is for an increase in imports and further decline in the exploitation of indigenous coal. According to a 1972 U.N. report,[45] a national program, as implemented by regional coal boards, is continuing "rationalizing" the industry by reducing production and the coal labor force. Residential, commercial, and light industrial coal markets are evaporating; the electric power

industry will eventually be the only major consumer of coal, outside of the iron and steel sector. Even before the 1973 war and ensuing escalation of prices, "Electricite de France" decreased coal consumption in its power plants from 75 percent in 1969 to 50 percent in 1971. Actual figures varied in 1971 and 1972 (compared to the number of plants equipped to burn coal instead of oil or gas), since hydroelectricity capacity varied widely in those two years. A 1972-estimate of coal-fired electric power plants (including captive colliery plants) is about 37 percent, and 1973 figures approach 25 percent. As in the U. S., in many of the oil-converted plants, coal-burning equipment remains in place and some could be re-converted. World Coal(46) advanced this hypothesis in October 1974. France, however, is placing most of its hopes in an expanded nuclear program, reserving coal to the iron and steel market, although even here there has been a gradual decline in the use of coal and coke over the past few years. Rather than expand its coal mining industry, France is expected to expand imports.(46)

A.3.8 Federal Republic of Germany (FRG)

General

West Germany has extensive coal reserves, a well-organized industry, and a deliberate policy of cutting back coal mining, in keeping with developments of the other EEC members on the continent. The German rationale is predicated on a dependable supply of oil and gas, and a declining demand for coal. Like the rest of Europe, Germany predicts an annual energy demand increase rate of 3-5 percent per year, but gas from Gronigen and the North Sea is expected to supply the greatest share of this demand. The story of

German coal production illustrates their philosophy and its implementation. Coal production in Germany, as in many other nations, depends not only on the classic laws of supply and demand, but also on the stocks that are established both at pitheads and in the yards of the major consumers. Laws and regulations in Germany, as well as economics make it infeasible to adjust mining operations to short term changes in demand. Accordingly, a recent statement of the Federal Commissioner for Coal Mining estimated that pithead coal stocks "may build up to 21 or 22 million tons."[38] Most mining operations in Germany, particularly Ruhrkohle AG, which controls about 85 percent of the national production, are chronic money losers.[47] The Federal Government appears to have no choice but to keep injecting funds into the industry, however, as the alternatives are infinitely worse. Considering that Ruhrkohle is the most productive segment of the continental Western European coal production economy clarifies the dismal picture of the coal industry in the bulk of the EEC. The most efficient solution is to cut back marginal mines and labor forces (with appropriate pensions or relocations), increase mechanization (Germany is approximately 30 percent more productive than the rest of the continental partners because of more extensive mechanization), and coordinate with other EEC members on a common coal policy so that the most productive mines will survive. The Netherlands, for example, plans to close all mines in 1975 (but this decision was made prior to the oil embargo). One decision made in Germany, before the embargo and escalating oil prices, was to promote the construction of new coal-fired electric power plants. 6,000 MW are expected to be online by 1980, causing a demand for lignite and bituminous of 6,000,000 tons per year. FRG production is presented in Table A.7.

Table A.7. Coal Production in the Federal Republic of Germany

Year	Production (million metric tons)		Remarks
	Hard	Lignite	
1960	143.2	96.2	Lignite for smaller and local power plants
1961	143.6	97.3	Lignite for smaller and local power plants
1962	141.9	101.3	Lignite for smaller and local power plants
1963	142.8	106.7	Lignite for smaller and local power plants
1964	142.7	110.9	Lignite for smaller and local power plants
1965	135.5	101.9	Demand drop begins to impact
1966	126.3	98.1	Mine closings initiated
1970	101.3	n.a.	Impact of mine closings
1971	101.8	n.a.	Gas/oil changeovers initiated
1972	100.8	n.a.	Steel industry major source of demand,
1973	97.3	108.0	other sectors converting to oil/gas. Gronigen online

Outlook

A dichotomy exists in the future of the coal industry of Germany. On the one hand, it loses money, it has historically lost money, and it is expected to continue to lose money. On the other hand, it is vital to Germany and to Europe — even to the extent that marginal mines in the Community are closed down and German coal is imported as a more cost-effective solution. It is 30 percent more efficient than other mining industries on the continent — a mixture of fortuitous geology and structure, and a traditional respect for the role of the machine in industry. It is guaranteed a place in all future industrial planning. It is expected to become more profitable by concentrating on profitable high-volume, high-production operations, and closing operations below certain economic thresholds (a philosophy practiced by major coal operators in the United States with considerable success over the years). Yet, it is not expected that the German coal industry will make a profit, and, under subsidy, it will probably level out at the 80,000,000 ton per year level. Germany exports coal primarily to France, Denmark, Italy, and the Netherlands where German metallurgical quality coal is required in domestic iron and steel industries. Since imported coal is escalating in price and North Sea oil and gas development timetables are slipping, and since the state of nuclear power and its role in Europe is still questionable, the German coal industry might confront a Renaissance — except for the labor force problem. Germany has already had to import labor to run its factories, build its automobiles, and perform a large quantity of its "service labor." It is impossible to suddenly open additional mines, add shifts on mines currently operating, and, in short, create a significantly larger mining labor force in a short time. The German coal industry, barring a major depression that

would bring wages down and an unemployed labor force into mining, appears to have passed "the point of no return" and has stablized with a fixed base, a fixed work force, and a basically fixed market.

A.3.9 Netherlands

The mines of the Netherlands lie in Limberg Province, in the southern part of the country, and are part of a general formation extending across the Netherlands, from Germany into Belgium. A government policy has been promulgated to phase out all mining in the Netherlands by 1975, and despite the embargo and the rise in oil prices, this policy is still in effect. The reasons are twofold: the mines were non-profitable, although stocks were good, and the coming online of the Gronigen gas field has taken away the requirements for most energy supply from coal. The export of Gronigen gas pays for the imports of metallurgical coal, primarily from Germany.

Between 1960 and 1966, production only dropped from 12,000,000 metric tons to 10 million. But by 1971 production had dropped to 3.79 million tons; by 1972 to 2.8 million tons; and by 1973 to 1.7 million tons. The preceding paragraphs concerning the development and status of Ruhrkohle in general and the FRG coal industry in particular indicate the extent to which the Netherlands are phasing out their coal production. Should the energy crisis become much worse, and the price of both OPEC and North Sea oil hold above the $10 level, the Netherlands would increase its coal imports, but it is doubtful if they could reactivate this expiring industry.[42, 45]

A.3.10 The United Kingdom

General

The United Kingdom is the only component of the EEC in which coal has not only a vital place, but with a strong assist by governmental financing may have a viable future. Even though North Sea oil and gas are being developed by the U.K. at a rapid pace, coal is still the mainstay of the bulk of the country's industry and economy. The impact of the most recent coal strikes on the industry and lifestyles of the country gave high visibility to the continuing dependence on coal. The long-term outlook may be for gas to displace coal in much of the energy market; North Sea gas flows to England through several pipelines and a number of larger-capacity lines are scheduled to be completed shortly. But coal remains pre-eminent in U.K. energy planning. The U.K. is essentially "going it alone" in an attempt to maintain a viable coal industry in the face of hard economic facts that mining either must be considered a money-losing proposition, or must be supported by government subsidies. The Atlee Labour Government nationalized coal in the late 1940s; hence coal and its future is a government proposition. As the Chairman of the U.K. National Coal Board put it, "The question of how much coal should be mined is invariably answered by, 'How much can we afford to lose on it?'"[48] The U.K. launched what might be termed a "major salvage operation" in December 1972 when Parliament appropriated an outright Government subsidy of 720 million pounds for 5 years operation and cancelled an additional 475 million pounds in accumulated debts. Most of the subsidy was used to close unprofitable mines and to improve and enlarge more efficient mines and fields to be kept in operation. Much of the money

was absorbed in un-programmed (but not necessarily unexpected) wage increases acquired in two major strikes, and in escalations tracking the current worldwide inflation. The object of the 1972 plan was to break even in 1974 and turn a profit in 1975. The former was not attained; but the latter seems attainable, given 1975 economics.

Despite an official Government position of support and encouragement to the coal industry, production has dropped steadily throughout the United Kingdom. One reason, aside from an almost consistent scenario of labor unrest, was a drop in demand, primarily in the consumer sector. Domestic coal heating (fireplaces) was phased out as an air-pollution measure. In the industrial sector, progressive strikes in most major industries also reduced demand. Only in the electric power sector, where a petroleum fuel tax, structured to maintain an economic incentive for coal, did demand remain high. The iron and steel industry with its associated demands for coke and the production of producer gas, prior to the introduction of significant quantities of North Sea gas, continued to form the major demand base. As may be noted in Table A.8, only the severe winter of 1963/64 created any increase in a generally declining coal production picture.

Outlook

The U.K. has committed itself to rejuvenate its coal industry for several reasons:

- North Sea oil and gas will take over many of the energy components fueled by coal. The U.K. wishes to be free of requirements for coal imports. By use of indigenous coal in the iron and steel industry (5 million tons of coking plus 300,000 tons of coke were imported in 1972), the U.K. can assist its dangerously impacted balance of payments by becoming (once again) a major coal exporter to the continent.

Table A. 8. Coal Production in the United Kingdom

Year	Production (million metric tons)	Remarks
1960	196.7	
1961	193.5	
1962	200.6	Onset of severe winter.
1963	198.9	Severe winter.
1964	196.7	Normal, slight decline.
1965	190.5	Sharp decrease in labor force.
1966	177.4	Marginal mines closed, continued decrease in labor force.
1967	174.9	
1968	166.7	Trend continues, more mines shut. Start of economic downturn.
1969	153.0	
1970	144.6	Economic recession, begins upturn,
1971	147.2	demand increases.
1972	121.8	Several new oil and gas-fired power stations online — other components of demand sector generally up.
1973	129.9	

- In March of 1972 the Coal Industry Act gave the National Coal Board extensive powers in the capital improvements, borrowing, social welfare, pensions, subsidies, grants, etc. in order to put the nationalized coal industry (which was formed from a large number of privately-owned mines in the Atlee Labour Government) on an integrated, rationally-operated basis. This would give the U.K. a firm base of operations, assuming maintenance of reasonable labor relations.

- Given the coincidental impact of middle-eastern oil prices and its inflationary side effects, with the disappointing record of nuclear power as a substitute for coal, the U.K. is uniquely able to establish a strong position in the EEC by having an integrated coal extraction, transportation, and marketing system that can support coal requirements both at home and on the continent. This depends on excessive pricing of Middle-Eastern oil, and a drive to lessen dependency on same.

A.3.11 Conclusions

Coal production in Europe is expected to continue its decline. Despite high oil prices, an essentially irreversible trend in the EEC is to de-emphasize coal, close down marginal and uneconomical mines, and subsidize producing mines; overall output continues to decline. Increases in production in the U.K. will not be sufficient to offset this trend, because the primary requirement for expanded coal production is a resource of trained labor. None now exist, nor is any likely to be forthcoming. That portion of the European labor force currently in the coal extraction industry will gradually diminish by attrition, with only a small percentage of replacements joining the force.

The situation is somewhat parallel to that in the United States, where the goals of "Project Independence" and "Energy

Supply and Environmental Coordination Act of 1974" dictate an expansion of the U.S. coal industry to (in the opinion of this author) an unrealistic degree. Mine production cannot be increased overnight; even new strip mines (a marginal European option) cannot be created without the acquisition of massive draglines, shovels, and heavy extraction machinery (2-3 year backlog). The U.S. is faced with a deteriorating eastern rail system while Europe would have to order extensive open hopper cars or rehabilitate many aging cars formerly in the bulk materials transport configuration. Both areas are faced with obsolescent underground mines. Mining Enforcement and Safety Administration (MESA) has caused upgrading (or closing) of many mines in the eastern U.S.;[49] economics has dictated similar actions in Europe. In short, Europe may change the rate in the decline of coal production, and lessen the plunge to alternative fuels, but at best will only postpone the inevitable.

A.4 ENERGY IMPORTS

Data have been developed to illustrate the current sources of energy imports to the Western European community. These data have been summarized in Table A.9. The predominant role of the OPEC countries as oil and (along with the Netherlands) gas suppliers is plainly evident.

Table A.9. Current European Energy Imports

EXPORTING COUNTRY	W. Germany Oil	W. Germany Gas	W. Germany Coal	France Oil	France Gas	France Coal	UK/Ireland Oil	UK/Ireland Gas	UK/Ireland Coal	Italy Oil	Italy Gas	Italy Coal	Denmark Oil	Denmark Gas	Denmark Coal	Netherlands Oil	Netherlands Gas	Netherlands Coal	Belgium/Lux. Oil	Belgium/Lux. Gas	Belgium/Lux. Coal
WEST EUROPE																					
Austria	0.036																				
Belgium/Lux.		28	4			401		264	49			37					22	30			
Denmark		158						22													
France		585	645					271	161		100	110					5	29		95	295
Italy						40															
Netherlands		85,205	1877		54,079	624		722			124	2		198						68,905	974
Norway	0.5		82				1.6	152						66	13						
Spain											334			286							
Sweden			28																		
U.K.						299					129	30		242	3		33	54		95	
West Germany		3				6261			381			2993		374	65		693	1550		106	6587
Yugoslavia											360										
EAST EUROPE																					
Czechoslovakia		185	1306												2						
East Germany			1117												33						
Poland			1564			1638						1607			1729			484			939
U.S.S.R.	2.8	17	50			1619	0.1			6.1				88	455	3.0				12	235
AFRICA																					
Algeria	11.4			8.1	7,531		1.1			3.5						1.1			2.4		
Angola (Cabinda)	1.6							7711		1.9						0.2					
Egypt	0.14						0.12									0.5					
Libya	28.5			9.8			15.1	126		22.2			0.9			5.2			1.3		
Nigeria	10.9			14.2			10.7				13,319					11.0			0.4		
LATIN AMERICA																					
Argentina							0.18														
Venezuela	3.7			1.9			5.0	207		1.3						0.4			1.1		
MIDDLE EAST																					
Abu Dhabi* / Dubai*	6.3			11.5			5.5			1.1						4.8					
Iran	9.8						13.2									7.8					
Iraq	3.1			16.6			33.5			22.3						5.4			2.1		
Kuwait	4.9			12.3			21.9			13.7	144		0.5			13.5			2.6		
Qatar	1.1			3.1			4.4			3.9						4.2					
Saudi Arabia	19.0			23.8			20.9			25.6						21.4					
NORTH AMERICA																					
Canada							0.1											36			
U.S.A.	17.0		3289			1091						3323						1472			1016
AUSTRALIA						69			1076									525			
SOUTHEAST ASIA																					
Indonesia							0.2					1126			40	0.9					
OTHERS			430			384	0.6				175						43	112		36	679

*Export/Import Statistics often collectively reported as "United Arab Emirates" (also including smaller oil-producing Shiekhdoms)

UNITS: OIL — Million Metric Tons; SOURCE: Petroleum Encyclopedia 1973
GAS — Kilocalories or "Teracalories"; SOURCE: U.N. Annual Bulletin of Gas Statistics for Europe — 1972
COAL — 1000 metric tons; SOURCE: U.N. Annual Bulletin of Coal Statistics for Europe — 1972

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Appendix B

ELECTRICITY

B.1 INTRODUCTION

Electrical energy generation has always been a key issue in the energy pattern of a country. It draws on all available energy sources for input. It delivers power to all consumption sectors. This power is in a form adequate to be transported, imported, or exported. As time passes, the fraction of energy input which is transformed into electricity increases. As an example, for the U.S., this fraction was 15.5 percent in 1960, 21 percent in 1970, and is expected to be 33.4 percent in 1985.(1)

The electrical energy generation values discussed in this appendix represent pre-embargo projection values as well as historical data. A discussion of changes in the demand for electrical energy as well as shifts in fuel mix are discussed in Section 3.2 of the main report.

B.2 ELECTRICITY PRODUCTION AND CONSUMPTION IN WESTERN EUROPE

B.2.1 Total Production and Consumption

Shown in Figure B.1 are the total production figures for all the countries of Western Europe considered. The total production is further broken down into thermal, hydroelectric and nuclear generation. From 1965 to 1972, these data are historical.(2) From 1973 to

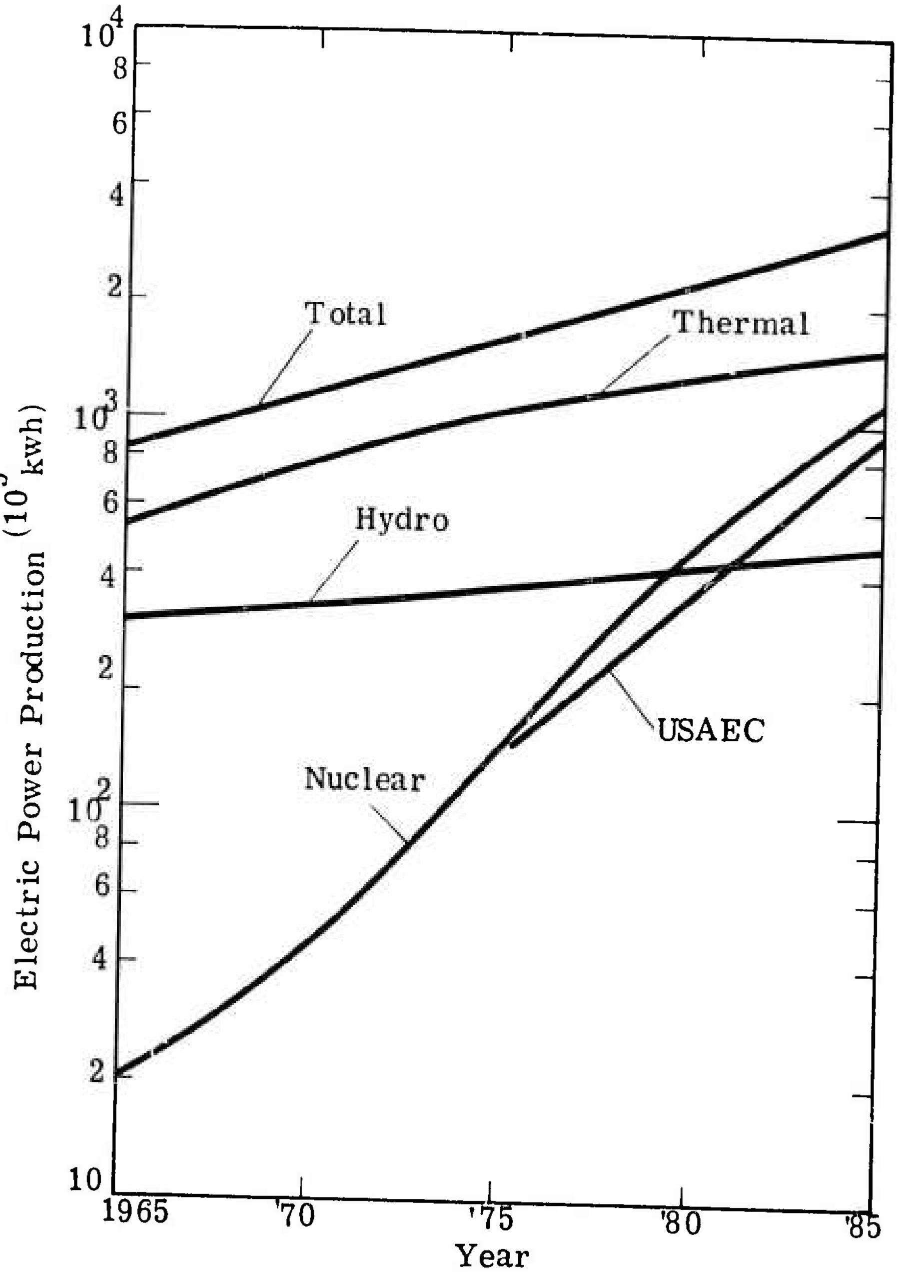

Figure B. 1. Electricity Production of Western Europe OECD and EEC(9) Sources

1985 we have used current OECD[3] and EEC[4] projections. USAEC projections (most likely case) for nuclear electricity[5, 6] through 2000 have been added for comparison. Figure B.2 presents the breakdown by the consuming sectors, such as energy, commercial and residential, industry, and transportation

B.2.2 Electricity Production by Country

This section presents the electricity production figures for the most important European countries separately. As a rule, we will concentrate on the main Common Market countries and add important countries outside the EEC(9). For ease of comparison, the data will be presented in graphs giving the total, thermal, hydroelectric and nuclear electricity produced in KWH as a function of time for each country.

As previously, we used 1970, 1971, and 1972 data from the OECD statistics and thereafter we have used projections available from the OECD, the EEC and individual countries[7-12] through 1985.

West Germany (Figure B.3) has little hydroelectric power and is mainly thermal. It will augment its thermal generation by 50 percent through 1985. The nuclear generation will be strongly increased, so as to cover one-third of the needs by that date.

The United Kingdom and the Republic of Ireland have been taken together (Figure B.3). These countries have some nuclear and hydroelectric power, but the generation is mainly thermal at this time. Nuclear energy should cover one-third of the needs by 1985, if the English nuclear program is implemented shortly. This program is still under discussion.

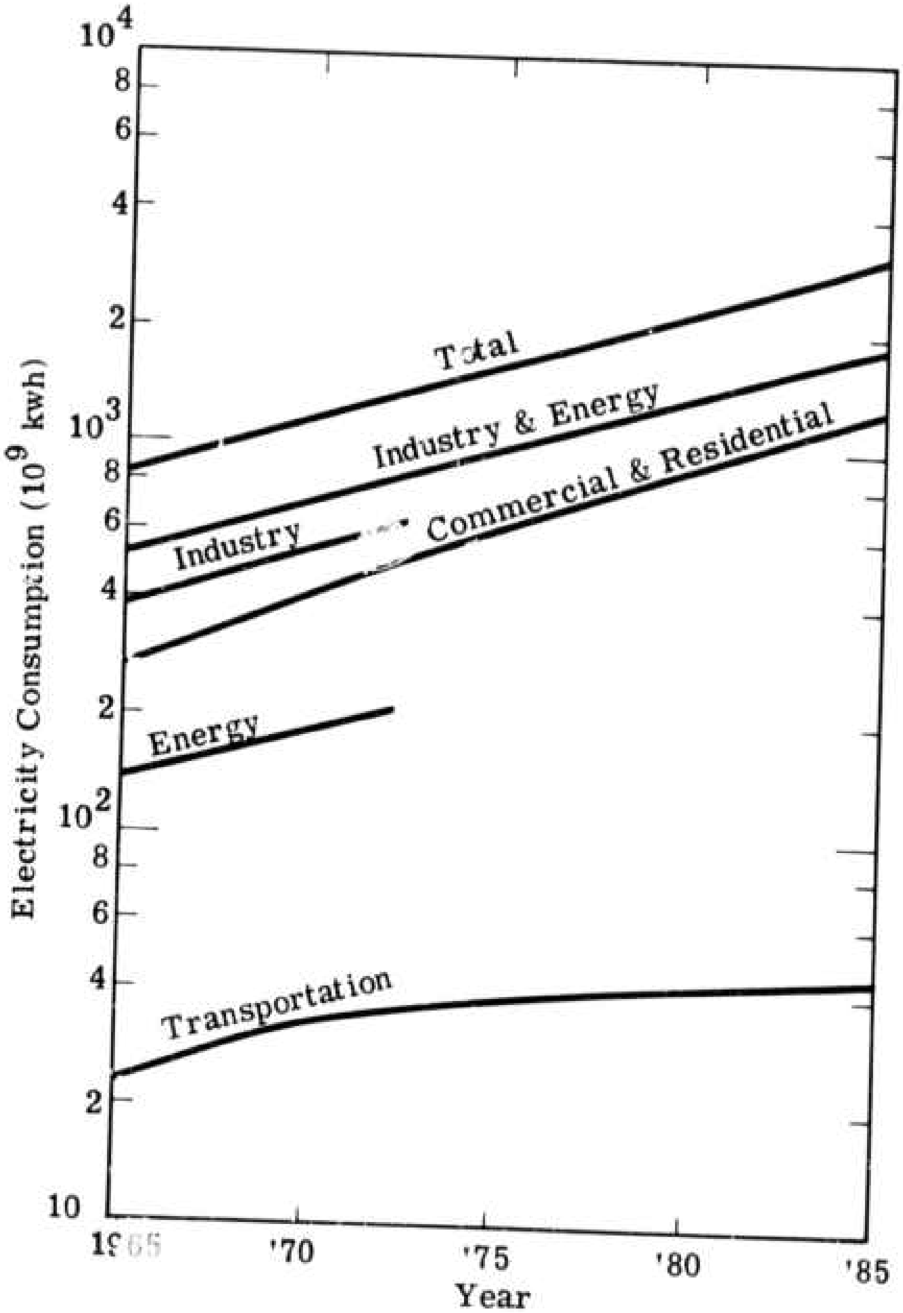

Figure B.2. Electricity Consumption of Western Europe by Consuming Sector

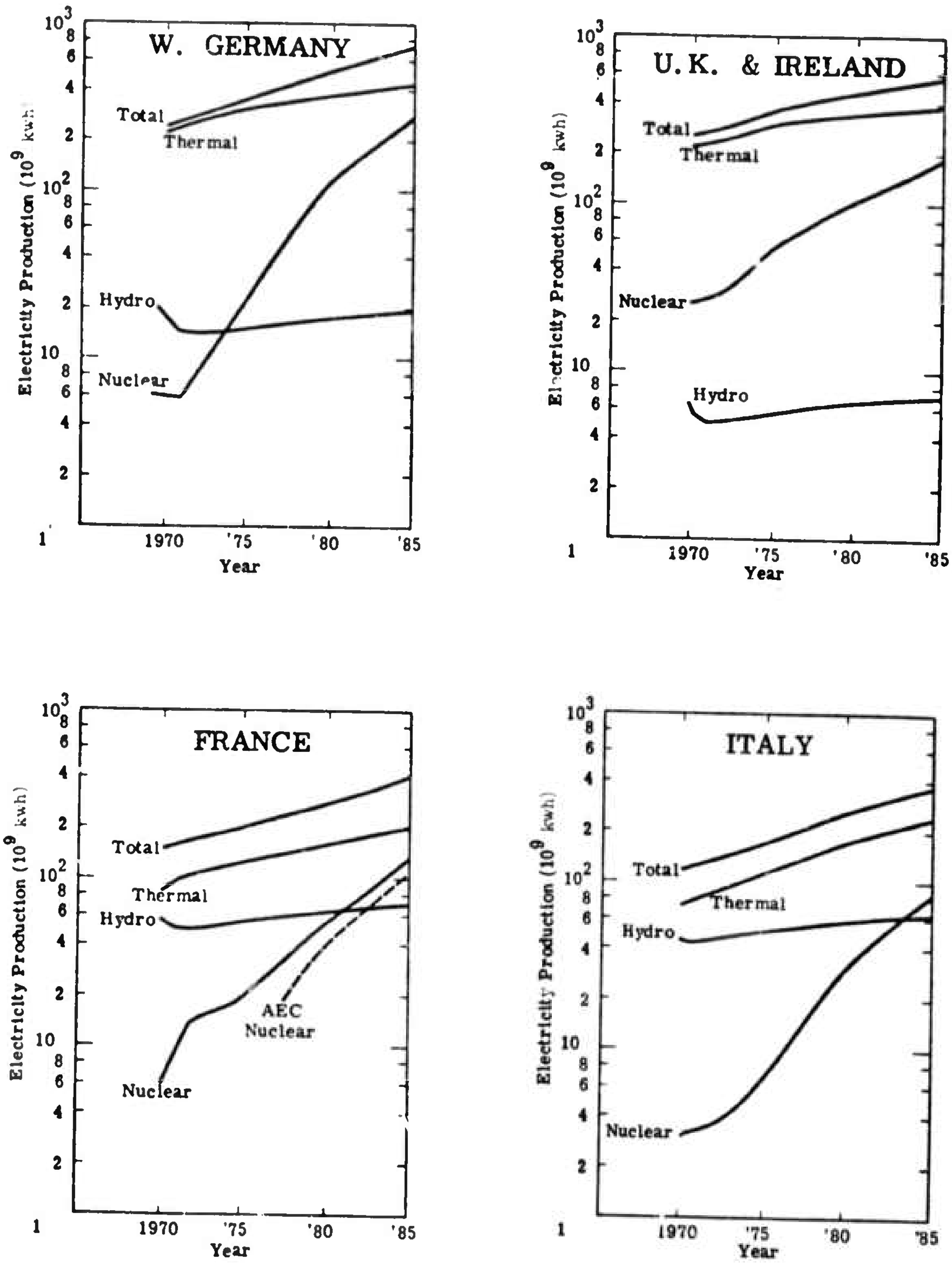

Figure B.3. Electricity Generation Forecast for W. Germany, the United Kingdom, France, and Italy

France (Figure B.3) has a large hydroelectric capacity, which it plans to extend by as much as 10 percent through 1985. But it will level off at that time. The French government announced at the end of 1973, that the thermal capacity will not be extended after 1980, the bulk of the effort being taken over by the nuclear plants which corresponds to doubling their production by 1985.

Italy (Figure B.3) has a strong hydroelectric sector, which will increase slightly. The thermal generation increase will follow the demand. Nuclear generation is still small but will be boosted up to 25 percent of the demand by 1985.

The Netherlands' electrical plants (Figure B.4) are purely thermal. Nuclear electricity generation will be increased to cover 25 percent of consumption by 1985.

Belgium's electricity production (Figure B.4) is at this time nearly entirely thermal. Hydroelectric capacity is very small (about 1.5 percent of thermal). Belgium is striving for nuclear power and hopes to have one-third of its needs covered by nuclear generation in 1985.

Denmark's electricity (Figure B.4) is totally thermal. It has not yet decided to go nuclear. If it does, about 8 percent of the needs would be covered by nuclear capacity in 1985.

Sweden (Figure B.5) has both large hydroelectric and thermal generation. It is working hard at developing the nuclear sector which should cover about one-third of the demand in 1985.

Norway (Figure B.5) is purely hydroelectric, and has exploitable hydraulic reserves which permit a 20 percent increase in hydroelectric generation through 1985. It relies to a small extent on imports from Sweden and plans some development of thermal power plants, in view of its North Sea oil reserves.

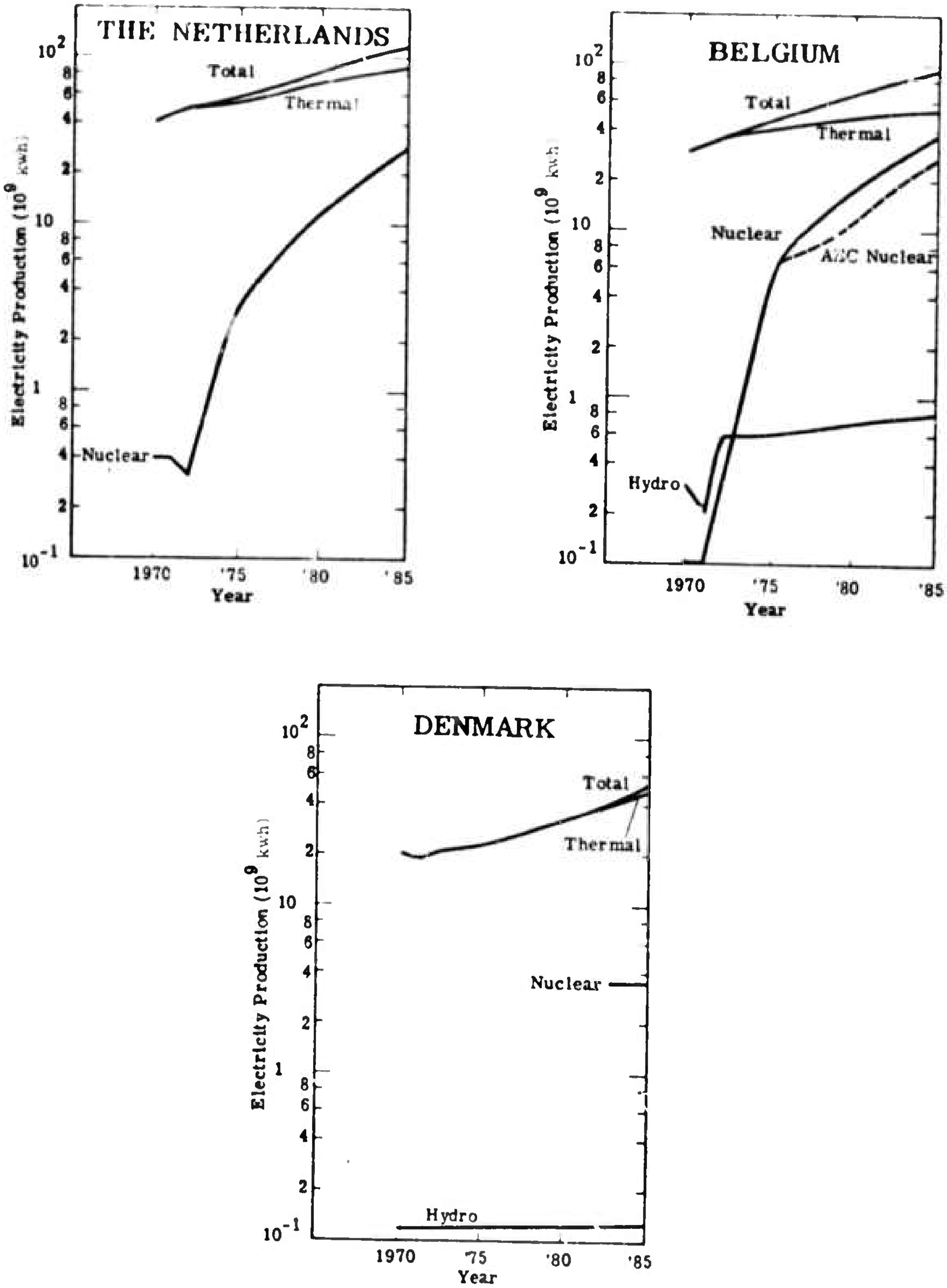

Figure B.4. Electricity Generation Forecast for the Netherlands, Belgium, and Denmark

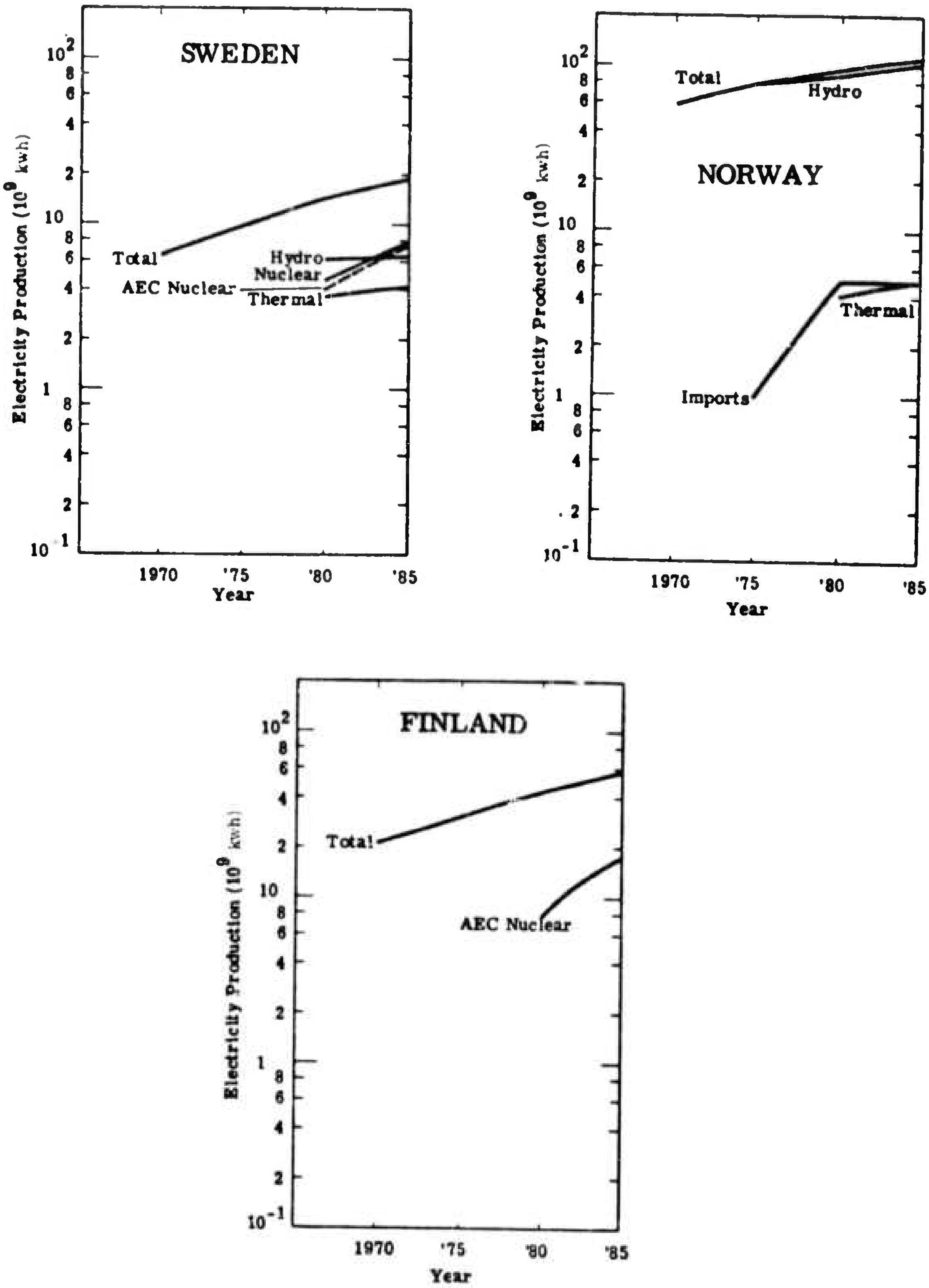

Figure B.5. Electricity Generation Forecast for Sweden, Norway, and Finland

Finland (Figure B.5) hopes to introduce nuclear power plants to cover one-third of its needs by 1985.

A summary of pertinent data is presented in Table B.1 for the year 1985.

B.3 THERMAL ELECTRICITY GENERATION

The figures for total thermal generation have been given in Section B.2, above, for individual European countries. It is of interest now to give the breakdown of the input to thermal generation in terms of solid, liquid, and gaseous fuels. This is done in Figure B.6, which presents a synopsis of the solid, liquid, and gaseous fuel inputs to thermal electricity generation for the Common Market.

Beginning with the solid fuels, the trend in the projections through 1985 is obviously downwards. The greater users are the United Kingdom and West Germany. France comes third, far behind, followed by the other countries. The only country which plans a steady increase in solid fuel consumption is Denmark.

The liquid fuels are on the increase in all countries — the planned increase rate in the mid-1980s is less than in the mid-1970s, however. The gaseous fuels are also on the increase everywhere. The projected increase rates are lower, however, than those for liquid fuels in the mid-1980s. A summary of the situation as projected for the year 1985 is presented in Table B.2.

B.4 HYDROELECTRIC GENERATION

The basic data have been presented in Sections B.1 and B.2 in conjunction with other methods of producing electricity (see Figure

Table B.1. Projected West European Electricity Production for 1985 (in Units of 10^9 KWH)

Country	Total Production	Thermal Production	Hydro Production	Nuclear Production
Belgium	91.2	52.1	.8	38.3
Denmark	52.2	48.0	.1	4.1
France	410.4	205.2	69.1	136.1
Germany	732.9	439.7	19.2	274.0
Italy	377.8	228.0	63.3	86.5
Luxembourg	11.4	4.9	1.2	5.3
Netherlands	117.3	87.9	.1	29.3
U.K. Ireland	576.1	379.8	7.0	189.3
Total EEC	2369.3	1445.6	160.8	762.9
Norway	112.0	5.0	100.0	--
Sweden	187.0	43.0	64.0	80.0
Finland	60.0	--	--	26.0
Total West Europe	3164.9	1559.1	485.4	1120.4

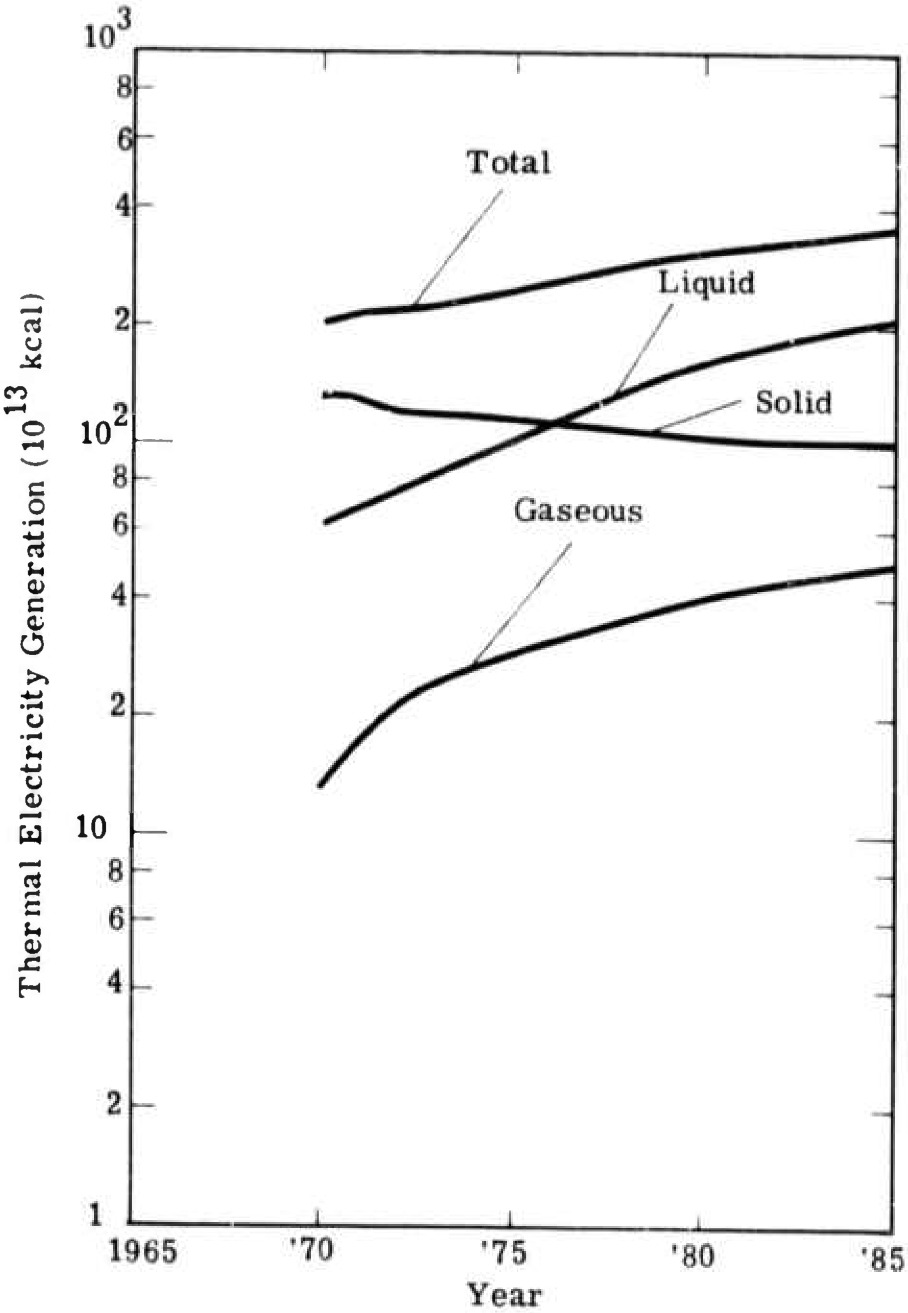

Figure B. 6. Summary of Fuel Inputs to Thermal Electricity Generation in Western Europe

Table B.2. Projected West European Input to Thermal Electricity in 1985 (in Units of 10^{13} kcal)

Country	Solids	Gas	Oil	Total
Belgium	2.1	2.9	6.8	11.8
Denmark	7.5	--	4.0	11.5
France	6.3	5.2	34.9	46.4
Germany	46.9	16.9	35.6	99.4
Italy	2.9	2.2	46.4	51.5
Luxembourg	--	.1	1.0	1.1
Netherlands	--	14.7	5.2	19.9
U.K.	24.6	4.9	58.1	87.6
Total EEC	90.3	46.9	192.0	329.2
Total West Europe	100.3	49.9	204.3	354.5

B.1). Figure B.7 presents the breakdown of the projected hydroelectric generation by country through 1985, with the total values added for the EEC and the OECD. The non-EEC countries are the great hydroelectric energy producers in Europe, their production being roughly double that of the EEC countries. The EEC countries, France and Italy are the most proficient and are almost equal.

From this figure one can infer that the development of hydroelectric power is much slower than that of thermal and nuclear power. It is still expected to grow at a rate of 2.5-3.0 percent annually in the next ten years, through 1985, in practically all the hydroelectricity producing EEC countries. A leveling off is then expected, as European sites suitable for hydroelectric plants are becoming more and more difficult to find, at least at current electricity prices, except in Norway and Sweden, which have vast mountainous and sparsely settled territories and have always relied very heavily on their hydroelectric resources.

B.5 NUCLEAR ELECTRICITY GENERATION

B.5.1 Forecast of Installed Nuclear Capacity

Figure B.8 provides a summary of the projected generation of nuclear electricity for OECD Europe, the EEC(9), and its member countries (see Figure B.8). The projections are those prepared by OECD prior to the oil embargo. The most important countries are West Germany, France, and the United Kingdom, producing 270, 200, and 190 billion KWH, respectively, in 1985.

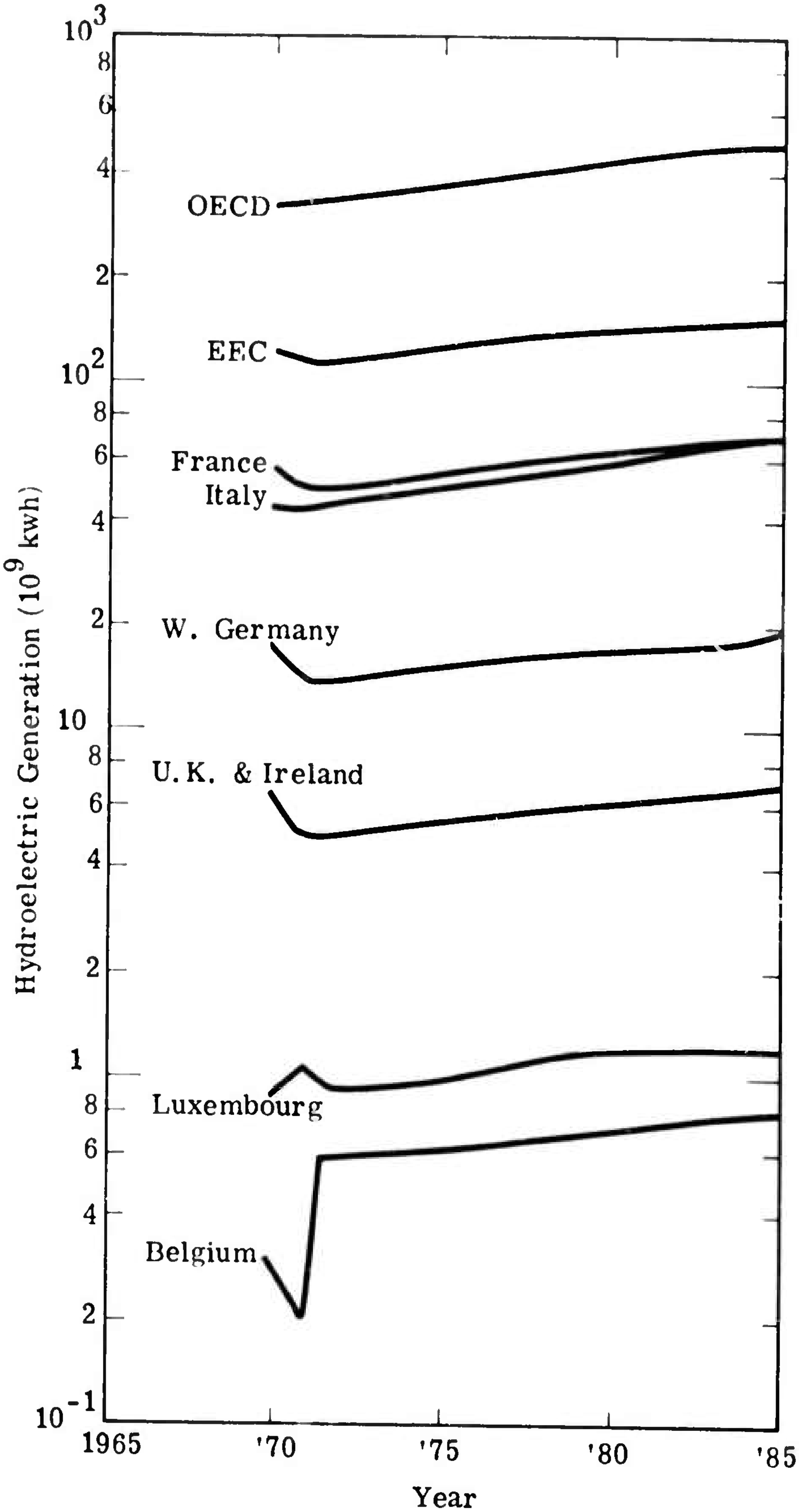

Figure B.7. Summary of Hydroelectric Power Generation by Countries

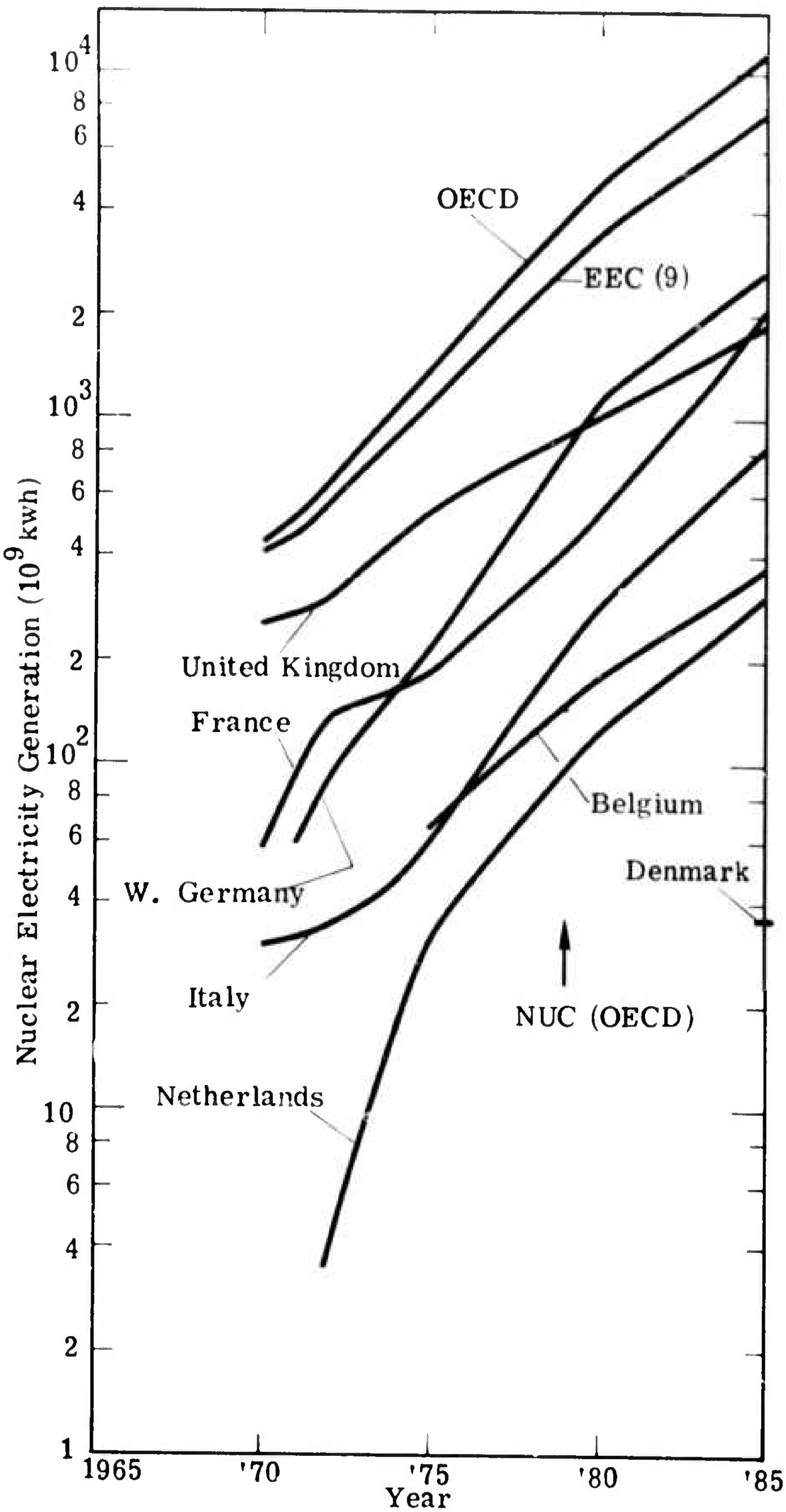

Figure B.8. Summary of Nuclear Electricity Generation by Country

France has recently announced her intention to discontinue ordering fossil fired power plants as of 1975 and to go nuclear for all new plants after that date. In contrast, England, although abiding by its nuclear power projections, has only recently committed itself to a particular line of nuclear reactors (Steam Generator Heavy Water Reactor), a fact which will introduce serious delays in the development of nuclear power. However, when totals for whole Western Europe are concerned, we do not expect that such excursions will bring substantial errors.

The most likely case projections of the USAEC for nuclear power development in Europe are in general agreement with the projections shown in the previous figures, but the USAEC forecasts assume a somewhat slower development of nuclear power than forecast by the Europeans. This difference largely reflects licensing slowdowns which have been encountered in this country, but which have not, as yet, been experienced to a significant degree in Europe. However, increasing environment concerns and "anti-nuclear" pressures may increase the length of time required to construct a nuclear plant in Europe. If the Europeans begin to experience licensing delays similar to those experienced in this country, the USAEC projections, which call for slower nuclear growth, are apt to be more accurate.

B.5.2 Uranium and Separative Work Requirements

We now consider the question of the input to the nuclear reactors, i.e., the requirements in uranium ore (U_3O_8) and the separative work to be provided in SWU (separative work units equivalent to one kg of separative work).

The projections given below are based on USAEC projections, which are the most reliable projections available from 1985 to the year 2000. The projections assume plutonium recycle. The advantage of plutonium recycle is fuel savings. In the steady state, after a few core reloads one uses 30 percent less fresh uranium in the fuel when one runs on self-generated plutonium. In a growing nuclear system like Western Europe's, where new reactors will be put on the line each year, the economy is less, but nevertheless reaches 10 to 15 percent savings in uranium requirements.

Although the British have announced they do not contemplate recycling. the AEC, assumed when calculating their projections, that all the European countries would recycle.

The tails assay (U_{235} remaining in the waste from the gaseous or other diffusion plants) is another parameter of the study. A value of 0.3 percent enrichment plant tails assay is assumed for the data presented (a lower value would save uranium but requires more separative work, a higher value the reverse).

The plant capacity factor (ratio of the electrical energy actually produced to the energy the reactor would produce when running at its rated capacity without interruption the whole year) is assumed to be 40 percent the first year of operation, 65 percent the second and third years,and 75 percent the fourth through fifteenth year. Then it is dropping linearly 2 percentage points per year to a minimum of 25 percent. In the U. S. the average capacity factor for all operating reactors was 72.9 percent in 1972.(13)

Figure B.9 gives the annual uranium ore demand for all Western Europe in short tons of U_3O_8 through the year 2000 for the two cases with and without recycle. One sees that without recycle

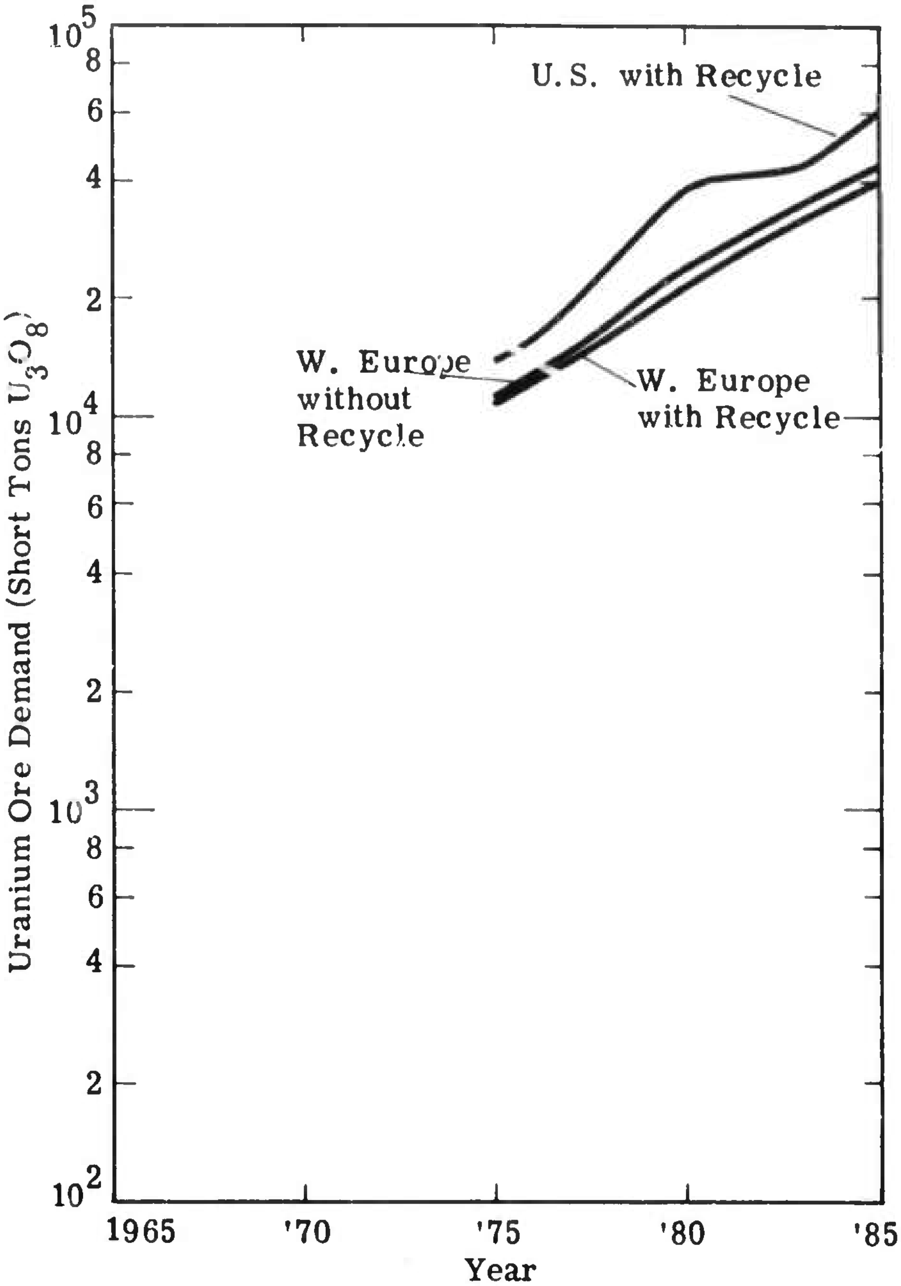

Figure B.9. Annual Uranium Ore Demand

the demand is between 10 and 15 percent higher. In what follows we will omit the case without recycle. The U. S. curve (with recycle) has been added for comparison. The uranium ore requirements will be like 40,000 short tons of U_3O_8 by 1985 and 100,000 by 2000 (with Plutonium-recycle).

Figure B. 10 gives the annual separative work requirements in SWU for Western Europe with the U. S. curve added. Western Europe will require 14 million SWU by 1985 and as much as 42 million SWU by 2000.

B. 5.3 Availability of Uranium and Enrichment Services to Western European Countries

Uranium Ore Sources and Uranium Production Capacity

An estimate of the free world uranium resources[14] can be found in Table B.3. Reasonably assured reserves refer to uranium which occurs in known ore deposits of such grade, quantity, and configuration that it can, within the given cost range, be recovered with currently proved mining and processing technology.

Estimated additional resources refers to uranium surmised to occur in unexplored extensions of known deposits or in undiscovered deposits in known uranium districts, and which is expected to be discoverable and exploitable in the given cost range. The tonnage and grade of estimated additional resources are based primarily on knowledge of the characteristics of deposits within the same districts.

The U. S. figures do not include 90,000 tons by-product U_3O_8 from phosphate and copper mining potentially recoverable at a cost of $10 per pound or less through the year 2000.

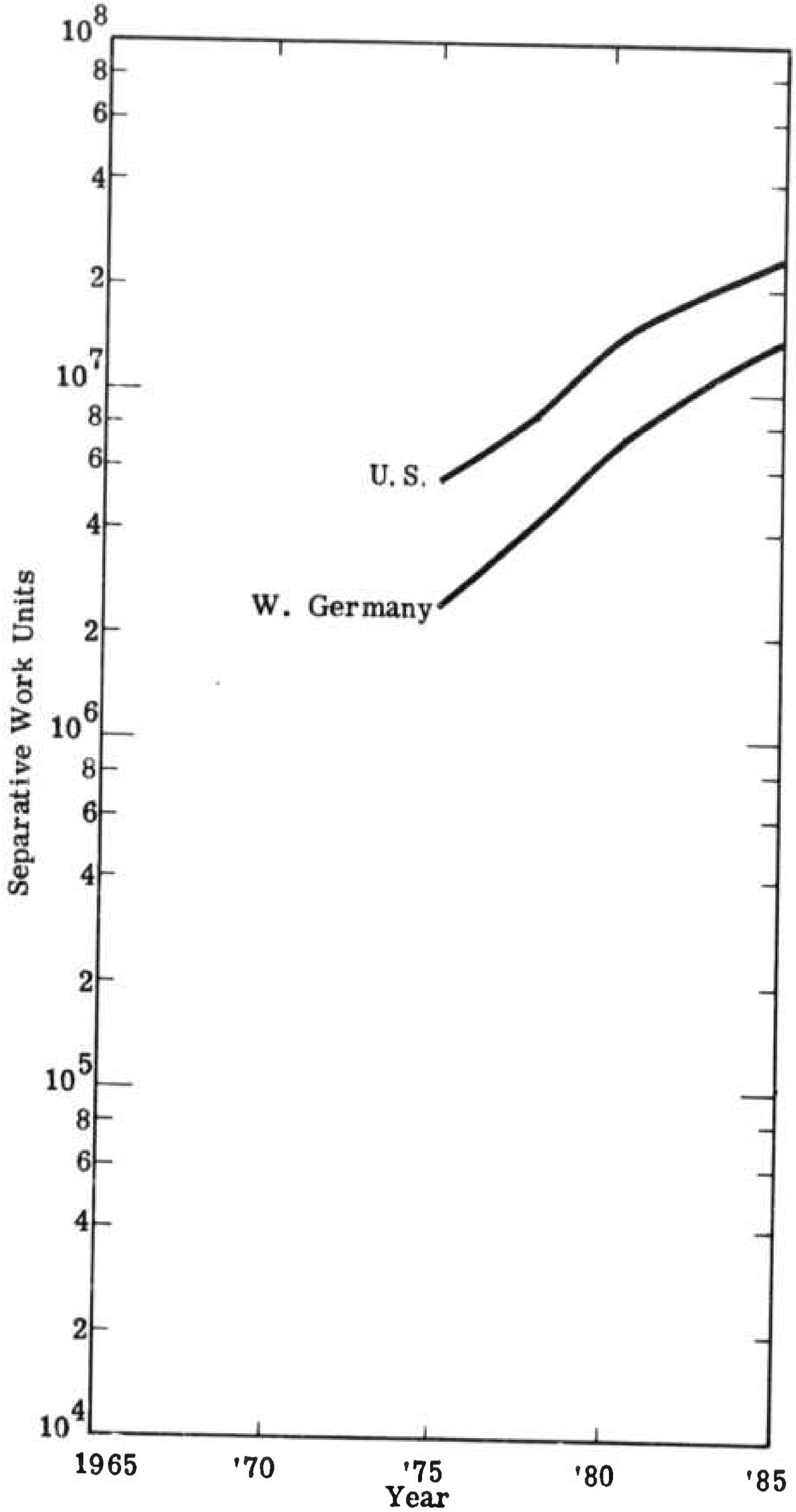

Figure B. 10. Separative Work Requirements

Table B.3. Estimated Free World Uranium Resources
(Recoverable at less than $10/lb U_3O_8)
(thousand short tons)
(January 1973)

Country	Reasonably assured	Estimated additional	Total
Australia	140.0	48.0	188.0
Canada	241.0	247.0	488.0
France	47.5	31.5	79.0
Gabon	26.0	6.5	32.5
Niger	52.0	26.0	78.0
South Africa 1/	263.0	10.4	273.4
U. S.	340.0	700.0	1040.0
Other 2/	67.5	67.5	135.0
Total	1177.0	1137.0	2314.0
Reserves at higher cost ($10-$15/lb. $U_3)_8$	886.0	821.0	1707.0

1/ Includes South West Africa

2/ Includes Argentina, Brazil, Central African Republic, Spain and others.

From the same source, Table B.4 shows estimated production capacities for the major producing areas in the free world. It is obvious from the table that the great producers of the free world are the U.S.A., Canada, and South Africa. The countries with the largest reserves are the same, plus Australia. It is thus not appropriate to divide producers into those who will supply Western Europe and those who will supply other customers, and we will now compare the annual demand of the U.S. and Western Europe (Figure B.11) as they can be found in the AEC projections and in an Atomic Industrial Forum Report.[9] Total free world production figures obtained from the U.S. Bureau of Mines[15] have been added.

It is first seen that U.S. requirements fall short of maximum feasible U.S. uranium production in 1980 and as of that date of this trend reversal, the U.S. will draw on foreign ore sources. Western Europe requirements are about two-thirds of the U.S. requirement. The U.S. and Western Europe requirements for 1980 are about twice the free world production in 1973. One can thus expect such countries as Canada, Australia, and South Africa to be very important for the U.S. and especially the Western European economies from 1980 on for the supply of uranium ore.

Another important consideration when studying uranium ore resources is the total amount of known reserves obtainable at a certain price. Figure B.12 shows the cumulative U_3O_8 requirements compared with the levels of known reserves.

The cumulative free world demand, which is obviously between the cumulative world demand and the U.S. and Western Europe demand, will cut the level of reasonably assured free world resources at $10/lb somewhere around 1987 and the free world reserve at $10/lb

Table B.4. Free World Uranium Production Capacities
(short tons U_3O_8)

Countries	1973	Planned for 1975	Attainable 1978
Australia	--	1,000	6,000
Canada	6,000	8,500	14,000
France	2,300	2,300	2,600
Gabon	780	780	1,560
Niger	975	1,950	1,950
S. Africa	5,370	5,000	8,000 est.
U.S.A.	19,000	19,000	34,000
Other	575	1,470	1,890
Total	35,000	40,000	70,000

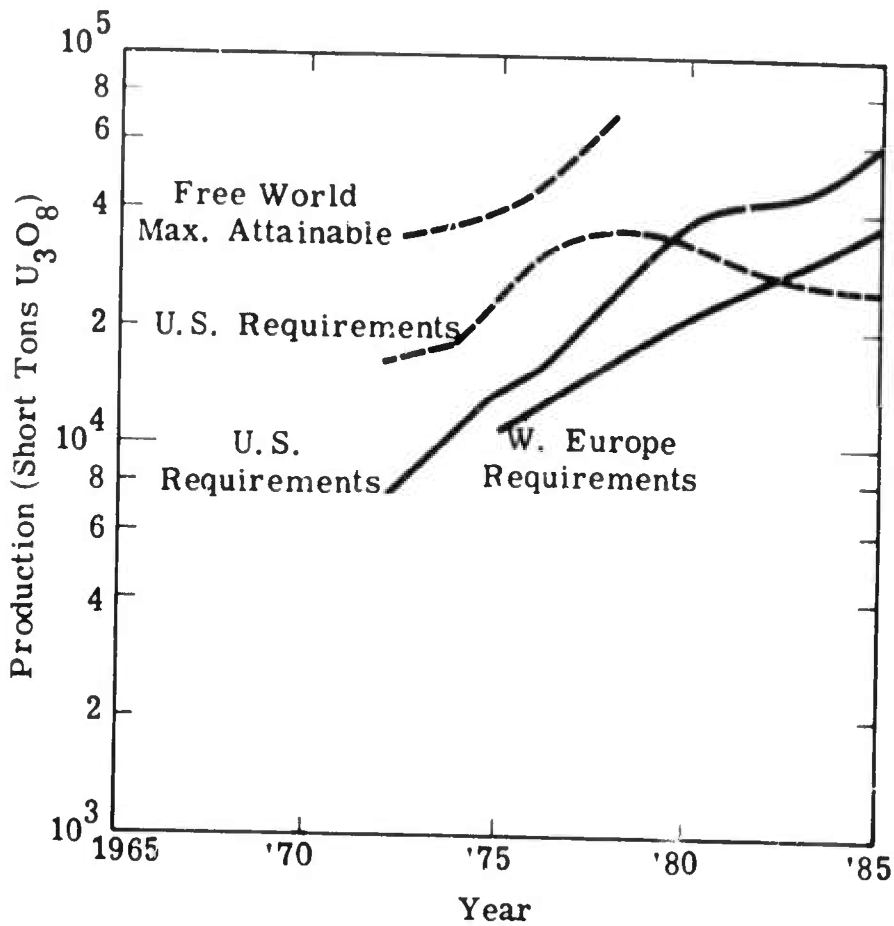

Figure B. 11. Uranium Production and Requirements

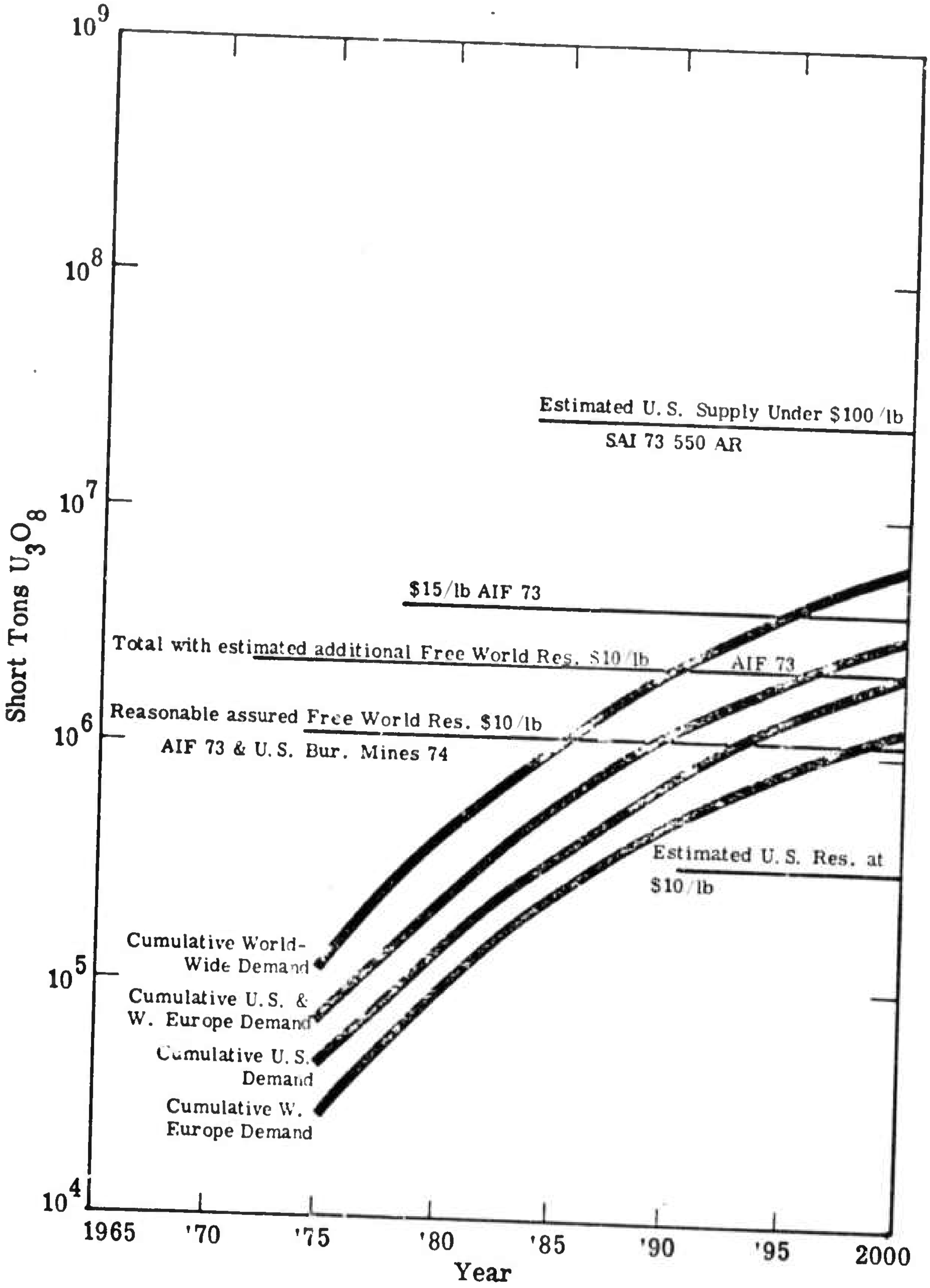

Figure B.12. Uranium Known Reserves and Cumulative Requirements

with additional estimates in 1997. It is thus to be expected that the uranium price will rise substantially to permit further exploration and mining. This is not expected to be catastrophic for the development of the nuclear power industry in Europe, as the price of ore amounts to only a small fraction (on the order of 6 percent presently) of the total electric power cost. Table B.5 gives the breakdown of electric power costs in its components for a 1000 MWe base loaded pressurized water reactor (PWR).

Enrichment Facilities

Projections by two sources[16, 17] indicate that there will be a potential shortage of enrichment in both the U.S. and the free world somewhere between 1978 and 1982. Figure B.13 shows the total world accumulative enrichment supply and demand curves through 1985 as given by the Atomic Industrial Forum in a 1972 report.[14] The curves shown include the high estimate of separative work available from non-U.S. sources. Further, the curves of Figure B.13 assume a completion of the United States Cascade Improvement Program and Cascade Uprating Program. The clear implication is that there will be a shortage of enrichment capability in the free world by the early 1980s. On the basis of the curves shown in Figure B.13, there will be a need to start up two large enrichment facilities (7,000 metric tons of SWU) at the beginning of 1982, and at least four such plants by 1985. This obvious need has lead to the push by the Europeans, under the Eurenco (European centrifuge program) to develop gas centrifuge plants and has led to a push in the United States to allow private industry to build new gaseous diffusion plants. Present plans by the private industry consortium of Uranium Enrichment Associates (UEA) call for building of a 9,000 metric tons of SWU plant by the early 1980s.[18]

Table B.5. Cost of Electric Power From 1000 MWe (Base-Loaded PWR)

Fuel Cycle Components	Cost (Mills/KWH)
Fabrication (@$70/kg U)	0.40
Uranium (@ $8/lb U_3O_8)	0.66
Conversion (@ $2.52/kg)	0.08
Enrichment (@ $32/SWU)	0.80
Reprocessing & Shipping (@ $45/kg U)	0.14
Plutonium Credit (@ $7.50/g)	(0.15)
Total Fuel Cycle Cost	1.93
All Other Costs (New Plants)	7.00-9.00
Total Electric Power Cost	9.00-11.00

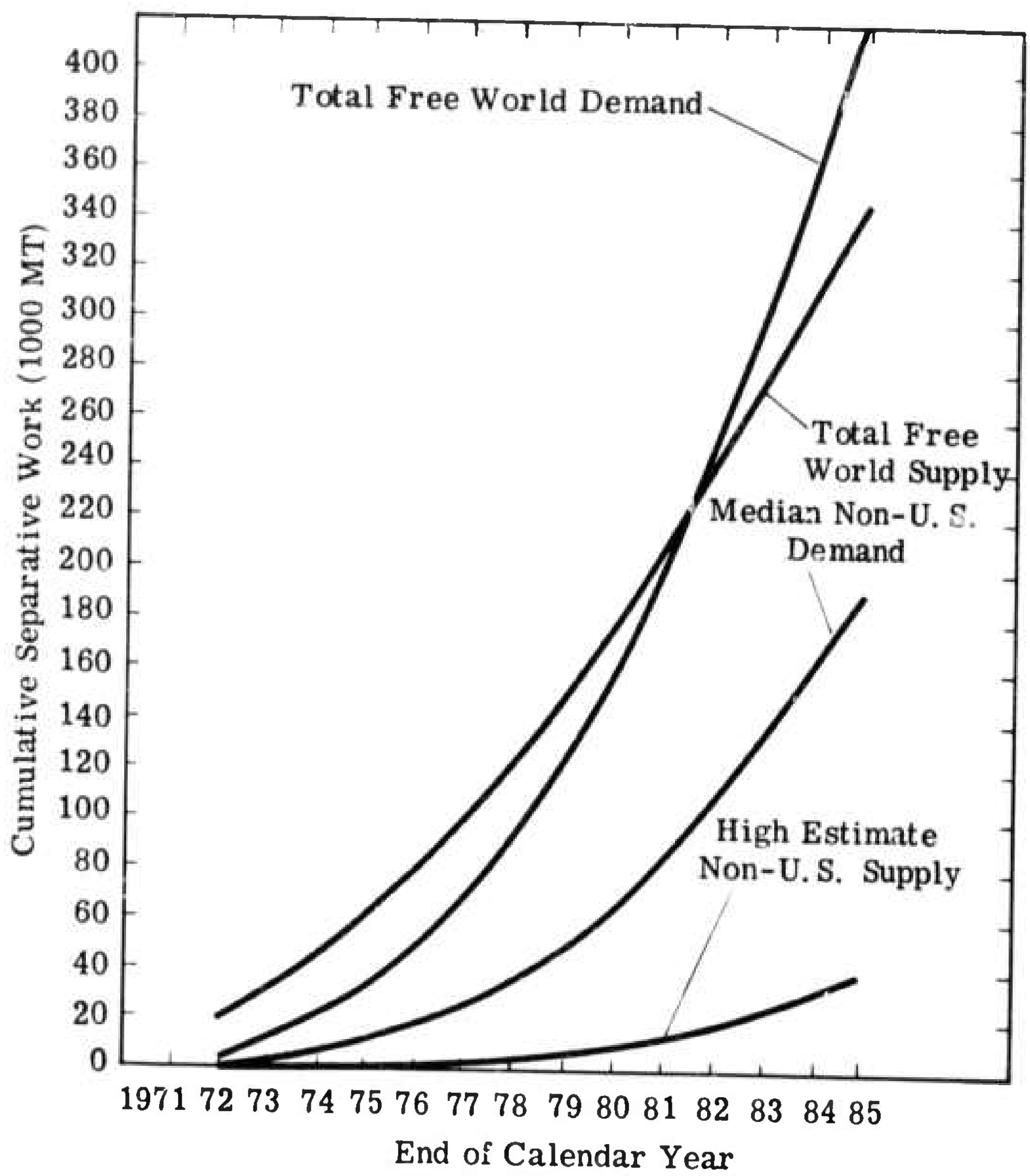

Figure B. 13. Cumulative Free World Enrichment Supply and Demand

Recent development since the oil embargo considerably clouds the picture as to the timing and magnitude of any future enrichment capacity shortage. The push by the Europeans to expand nuclear power to save oil imports would indicate a worsening of the enrichment shortage; however, recent economic developments have caused a considerable slowdown in nuclear plant construction in the U. S., and there are indications that several European countries are having trouble raising the capital needed to develop nuclear energy rapidly and nuclear plant starts are being delayed. Over the long run, a rise in the price of oil should mean an expansion in nuclear power which will require additional separative work. However, energy conservation measures in the U. S. and Europe, coupled with slowdowns in economic expansion and capital shortage problems seem to have slowed nuclear plant construction, indicating a few years delay in the time before new enrichment capacity will be needed by the free world. Thus, there still appears to be an obvious need to develop new enrichment capacity, but the period before any enrichment shortage may occur may well slip from the early to mid-1980s.

B. 5. 4 Special Problems with Nuclear Energy in Western Europe

Problems Connected with the High Population Density

Table B. 6 from the Foratom Conference in Florence, 1973,[19] shows that if one calculates the energy consumption per unit area, instead of per capita, it clearly emerges that in all but five European countries (the exceptions being Sweden, Norway, Finland, Spain, and Portugal) the average energy consumption density is greater — and in some cases very much greater — than in the U. S.

Table B.6. Energy Consumption Per Capita and Energy Consumption Per Unit Area

Country	Per Capita Power Consumption (kg coal equivalent) 1969	Energy Consumption Per Unit Area (tons coal equivalent per km^2) 1969
Austria	2, 994	264
Belgium Luxembourg	5, 429	1, 623
Denmark	5, 141	595
Finland	3, 575	54
France	3, 517	321
Germany (FR)	4, 850	1, 174
Italy	2, 432	429
Netherlands	4, 659	1, 791
Norway	4, 430	53
Portugal	603	59
Spain	1, 354	89
Sweden	5, 768	102
Switzerland	3, 175	478
United Kingdom	5, 139	1, 173
Average for Foratom Countries	3, 792	370
United States	10, 773	233
Japan	2, 515	709

In particular, the Netherlands, Belgium and Luxembourg, West Germany, and the United Kingdom, which have from 5 to 7 times more energy consumption per unit area than the U. S., are the countries expected to present more serious special problems, such as environmental impact, political opposition, and waste disposal.

In Switzerland, for example, a consensus country which resembles the United States politically, nuclear power plants have been delayed several years by political opposition and the setting up of adequate licensing procedures. Site availability is greater in the U.K. and France, which have long and scarsely populated coastlines.

Problems Connected with Considering Europe as Separate Independent Countries

Decisions and actions are not taken Europe-wide, due to the division in independent countries. Each country has a nuclear energy policy of its own, linked in a way to the national energy policy and overall politics. Examples of particular behaviors are as follows:

- The United Kingdom has postponed for one year its commitment to a particular line of reactors.
- France has recently (Spring, 1974) decided that from 1976 onward, all orders for electricity generating plants must be nuclear. It has also developed an advanced test breeder technology of its own, with the aim of having one 1,200 MWe fast breeder coupled to the electrical grid in the early 1980s.
- Norway, in view of the newly discovered oil fields in the North Sea in front of its doorstep and under the pressure of strong political opposition to nuclear energy from environmentalists, has decided not to go nuclear in the near future.

Competition exists among all European countries for access to uranium ore, enrichment services not to speak of reprocessing plants, waste disposal and plutonium recycle facilities. Solutions to problems are usually attempted on a national basis rather than a European basis. Euratom was set up as an attempt to solve these problems in common. It has failed on the technical level as it attempted to find and develop a line of European reactors. It still functions as a supply agency of fuel and enrichment services for its member states (the European economic community [EEC(9)] countries). These countries also shop for the same products and services separately and all over the world, including countries with centrally planned economies.

We can now take the individual countries in turn and examine their particular problems.

France has the most ambitious program of all the European countries in terms of growth rate of the nuclear generation capacity. It has committed itself to U.S. light water reactor (LWR) technology and is developing a manufacturing force of its own, which it tries to boost by offering reactors for sale worldwide (Iran, Arab oil countries, and the U.S.S.R.). France started early with fast breeder reactors and has one 250 MWe unit coupled to the grid. Thus it has technology and experience to offer in this area, as well as in the areas of fuel fabrication, fuel reprocessing and waste disposal. It has self-sufficiency in uranium at the moment and solid ties with Gabon and Niger for the future.

The United Kingdom has no problems regarding ore resources because of its links with Canada. It has a long experience with a diversified technology. It has only recently committed itself to a particular type of reactor (Steam Generator Heavy Water Reactor), thus delaying the upsurge of nuclear power.

Germany has no serious ore resources, nor fuel fabrication capacity, of its own. It committed itself long ago to U.S. LWR technology and developed an industry able to build it. It still lacks experience in fuel fabrication and reprocessing techniques. It has fuel and enrichment contracts with both the U.S. and U.S.S.R.

The other EEC countries are beginning their nuclear electricity generation slowly on the basis of LWR technology. The more advanced are Italy and the Benelux countries. Outside the Common Market, all countries except Norway are planning on LWRs, Sweden being the more proficient country. Norway has no plans for nuclear power for a long time.

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Appendix C

DETAILED ENERGY BALANCES

ENERGY CONSUMPTION PROSPECTS FOR WEST EUROPE

1962 — 10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	94.6	58.3	9.9	---	63.6	226.4
Industry Sectors*	96.8	92.9	1.6	45.4	141.4	378.1
Transportation Sectors	15.3	72.6	---	---	6.9	94.8
Total Final Internal Consumption (TFIC)	206.7	223.8	11.5	45.4	211.9	699.3
Electricity Generation	106.4	20.2	2.7	5.4	-134.7	(134.7)
Gas Manufacture***	50.8	---	---	-50.8	---	(50.8)
Non-Energy Use	---	17.5	---	---	---	17.5
Total Internal Consumption (TIC)	363.9	261.5	14.2	---	77.2	716.8
Bunkers	---	25.1	---	---	---	25.1
Total Requirements	363.9	286.6	14.2	---	77.2	741.9

1970	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	54.3	161.8	30.4	---	108.0	354.5
Industry Sectors*	74.9	201.0	26.9	37.1	190.3	530.2
Transportation Sectors	2.9	140.5	---	---	7.9	151.3
Total Final Internal Consumption (TFIC)	132.1	503.3	57.3	37.1	306.2	1036.0
Electricity Generation	118.1	69.0	13.0	6.2	-206.3	---
Gas Manufacture***	43.3	---	---	-43.3	---	---
Non-Energy Use	---	52.3	---	---	---	52.3
Total Internal Consumption (TIC)	293.5	624.6	70.3	---	99.9	1088.3
Bunkers	---	41.1	---	---	---	41.1
Total Requirements	293.5	665.7	70.3	---	99.9	1129.4

* Includes Consumption by the Energy Sector and Distribution Losses.
** Includes Input to Derived Gases.
*** Figures Given Are Input to Derived Gases.
****Figures Given Are Input to Generation in Thermal Equivalent

ENERGY CONSUMPTION PROSPECTS FOR WEST EUROPE

10^{13} KCAL (MTOE)	Solids	Oil** (1971)	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	44.4	173.4	35.5	---	117.2	370.5
Industry Sectors*	65.8	192.9	38.2	32.4	198.0	527.3
Transportation Sectors	2.5	149.5	---	---	8.0	160.0
Total Final Internal Consumption (TFIC)	112.7	515.8	73.7	32.4	323.2	1057.8
Electricity Generation	122.0	76.3	17.0	6.1	-221.4	---
Gas Manufacture***	38.5	---	---	-38.5	---	---
Non-Energy Use	---	54.3	---	---	---	54.3
Total Internal Consumption (TIC)	273.2	646.4	90.7	---	101.8	1112.1
Bunkers	---	42.7	---	---	---	42.7
Total Requirements	273.2	689.1	90.7	---	101.8	1154.8

		1972				
Commercial-Residential	39.5	187.4	43.9	---	123.1	393.9
Industry Sectors*	60.9	204.2	49.6	30.9	197.8	543.4
Transportation Sectors	2.0	159.1	---	---	7.9	169.0
Total Final Internal Consumption (TFIC)	102.4	550.7	93.5	30.9	328.8	1106.3
Electricity Generation	110.5	84.9	22.7	6.7	-224.8	---
Gas Manufacture***	37.6	---	---	-37.6	---	---
Non-Energy Use	---	56.8	---	---	---	56.8
Total Internal Consumption (TIC)	250.5	692.4	116.2	---	104.0	1163.1
Bunkers	---	47.2	---	---	---	47.2
Total Requirements	250.5	739.6	116.2	---	104.0	1210.3

* Includes Consumption by the Energy Sector and Distribution Losses.

** Includes Input to Derived Gases.

*** Figures Given Are Input to Derived Gases.

****Figures Given Are Input to Generation in Thermal Equivalent

ENERGY CONSUMPTION PROSPECTS FOR WEST EUROPE

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
1975						
Commercial-Residential	32.3	208.8	54.8	---	140.7	436.6
Industry Sectors*	60.2	237.9	64.6	30.1	220.0	612.8
Transportation Sectors	1.5	182.9	---	---	7.9	192.3
Total Final Internal Consumption (TFIC)	94.0	629.6	119.4	30.1	368.6	1241.7
Electricity Generation	104.9	109.0	28.3	7.1	-249.3	---
Gas Manufacture***	37.2	---	---	-37.2	---	---
Non-Energy Use	---	70.8	---	---	---	70.8
Total Internal Consumption (TIC)	236.1	809.4	147.7	---	119.3	1312.5
Bunkers	---	51.2	---	---	---	51.2
Total Requirements	236.1	860.6	147.7	---	119.3	1363.7
1980						
Commercial-Residential	23.2	250.1	79.5	---	207.6	560.4
Industry Sectors*	59.1	306.9	100.5	28.7	310.0	805.2
Transportation Sectors	1.0	231.0	---	---	8.6	240.6
Total Final Internal Consumption (TFIC)	83.3	788.0	180.0	28.7	426.2	1606.2
Electricity Generation	96.4	165.0	41.2	8.1	-311.3	---
Gas Manufacture***	36.8	---	---	-36.8	---	---
Non-Energy Use	---	102.5	---	---	---	102.5
Total Internal Consumption (TIC)	216.5	1056.1				
Bunkers	---	58.8	---	---	---	58.8
Total Requirements	216.5	1114.9	221.2	---	214.9	1767.5

* Includes Consumption by the Energy Sector and Distribution Losses.

** Includes Input to Derived Gases.

*** Figures Given Are Input to Derived Gases.

****Figures Given Are Input to Generation in Thermal Equivalent

ENERGY CONSUMPTION PROSPECTS FOR WEST EUROPE

		1985				
10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	19.4	305.4	108.8	---	288.1	721.7
Industry Sectors*	61.5	379.8	144.9	26.2	421.7	1034.1
Transportation Sectors	1.0	303.7	---	---	11.1	315.8
Total Final Internal Consumption (TFIC)	81.9	988.9	253.7	26.2	720.9	2071.6
Electricity Generation	92.7	204.9	49.9	7.6	-355.1	---
Gas Manufacture***	33.8	---	---	-33.8	---	---
Non-Energy Use	---	139.7	---	---	---	139.7
Total Internal Consumption (TIC)	208.4	1333.5	303.6	---	365.8	2211.3
Bunkers	---	65.5	---	---	---	65.5
Total Requirements	208.4	1399.0	303.6	---	365.8	2276.8

Commercial-Residential						
Industry Sectors*						
Transportation Sectors						
Total Final Internal Consumption (TFIC)						
Electricity Generation						
Gas Manufacture***						
Non-Energy Use						
Total Internal Consumption (TIC)						
Bunkers						
Total Requirements						

* Includes Consumption by the Energy Sector and Distribution Losses.
** Includes Input to Derived Gases.
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****Figures Given Are Input to Generation in Thermal Equivalent

ENERGY CONSUMPTION PROSPECTS FOR THE EEC(9)

1970

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	50.3	125.0	29.4	0.0	84.8	289.5
Industry Sectors*	65.1	166.2	25.8	33.1	141.9	432.1
Transportation Sectors	1.9	109.5	0.0	---	5.9	117.3
Total Final Internal Consumption (TFIC)	117.3	400.7	55.2	33.1	232.6	838.9
Electricity Generation	110.3	56.7	12.2	5.7	-184.9	---
Gas Manufacture***	38.8	---	---	-38.8	---	---
Non-Energy Use	0.0	45.3	---	---	---	45.3
Total Internal Consumption (TIC)	266.4	502.7	67.4	---	47.7	884.2
Bunkers	---	35.2	---	---	---	35.2
Total Requirements	266.4	537.9	67.4	---	47.7	919.4

1971

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	41.2	134.9	34.4	0.0	92.2	302.7
Industry Sectors*	55.9	157.5	36.7	28.2	146.7	425.0
Transportation Sectors	1.4	116.8	0.0	---	6.0	124.2
Total Final Internal Consumption (TFIC)	98.5	409.2	71.7	28.2	244.9	851.9
Electricity Generation	114.4	64.7	16.0	5.6	-200.7	---
Gas Manufacture***	33.8	---	---	-33.8	---	---
Non-Energy Use	0.0	48.4	---	---	---	48.4
Total Internal Consumption (TIC)	246.7	522.3	87.1	---	44.2	900.3
Bunkers	---	36.7	---	---	---	36.7
Total Requirements	246.7	559.0	87.1	---	44.2	937.0

* Includes Consumption by the Energy Sector and Distribution Losses.

** Includes Input to Derived Gases.

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****Figures Given Are Input to Generation in Thermal Equivalent

ENERGY CONSUMPTION PROSPECTS FOR THE EEC(9)

1972

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	36.5	145.8	42.5	0.0	96.3	321.1
Industry Sectors*	51.4	155.8	48.0	26.4	143.8	425.4
Transportation Sectors	1.2	122.8	0.0	---	5.3	129.3
Total Final Internal Consumption (TFIC)	89.1	424.4	90.5	26.4	245.4	875.8
Electricity Generation	102.9	72.2	21.5	6.1	-202.7	---
Gas Manufacture***	32.5	---	---	-32.5	---	---
Non-Energy Use	0.0	51.6	---	---	---	51.6
Total Internal Consumption (TIC)	224.5	548.2	112.0	---	42.7	927.4
Bunkers	---	40.4	---	---	---	40.4
Total Requirements	224.5	588.6	112.0	---	42.7	967.8

1975

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	27.2	163.2	52.5	0.0	111.7	354.6
Industry Sectors*	48.8	187.0	61.5	25.5	162.2	485.0
Transportation Sectors	0.0	142.4	---	---	5.4	147.8
Total Final Internal Consumption (TFIC)	76.0	492.6	114.0	25.5	279.3	987.4
Electricity Generation	96.9	93.3	26.9	6.3	-223.4	---
Gas Manufacture***	31.8	---	---	-31.8	---	---
Non-Energy Use	0.0	62.9	---	---	---	62.9
Total Internal Consumption (TIC)	204.7	648.8	140.9	---	55.9	1050.3
Bunkers	---	44.3	---	---	---	44.3
Total Requirements	204.7	693.1	140.9	---	55.9	1094.6

* Includes Consumption by the Energy Sector and Distribution Losses.
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ENERGY CONSUMPTION PROSPECTS FOR THE EEC(9)

1980

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	16.8	197.2	74.9	0.0	162.2	451.1
Industry Sectors*	44.8	253.5	93.1	24.0	223.8	639.2
Transportation Sectors	---	182.6	---	---	5.9	188.5
Total Final Internal Consumption (TFIC)	61.6	633.3	168.0	24.0	391.9	1278.8
Electricity Generation	87.7	143.3	39.2	6.8	-277.0	---
Gas Manufacture***	30.8	---	---	-30.8	---	---
Non-Energy Use	0.0	87.5	---	---	---	87.5
Total Internal Consumption (TIC)	180.1	864.1	207.2	---	114.9	1366.3
Bunkers	---	51.9	---	---	---	51.9
Total Requirements	180.1	916.0	207.2	---	114.9	1418.2

1985

Commercial-Residential	10.5	229.7	96.6	0.0	227.3	564.1
Industry Sectors*	43.4	306.6	123.2	21.7	305.6	800.5
Transportation Sectors	---	236.7	---	---	7.0	243.7
Total Final Internal Consumption (TFIC)	53.9	773.0	219.8	21.7	539.9	1608.3
Electricity Generation	84.0	192.0	46.9	6.3	-329.2	---
Gas Manufacture***	28.0	---	---	-28.0	---	---
Non-Energy Use	0.0	119.7	---	---	---	119.7
Total Internal Consumption (TIC)	165.9	1084.7	266.7	---	210.7	1728.0
Bunkers	---	56.7	---	---	---	56.7
Total Requirements	165.9	1141.4	266.7	---	210.7	1784.7

* Includes Consumption by the Energy Sector and Distribution Losses.
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ENERGY CONSUMPTION PROSPECTS FOR GERMANY

1972

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	10.1	48.6	7.3	0.0	26.6	92.6
Industry Sectors*	18.1	33.1	10.4	9.8	42.6	114.0
Transportation Sectors	0.8	32.4	---	---	2.1	35.3
Total Final Internal Consumption (TFIC)	29.0	114.1	17.7	9.8	71.3	241.9
Electricity Generation	43.8	10.2	6.2	2.4	-62.6	---
Gas Manufacture***	12.2	---	---	-12.2	---	---
Non-Energy Use	---	11.0	---	---	---	11.0
Total Internal Consumption (TIC)	85.0	135.3	23.9	---	8.7	252.9
Bunkers	---	4.3	---	---	---	4.3
Total Requirements	85.0	139.6	23.9	---	8.7	257.2

1975

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	9.1	51.8	9.8	0.0	33.0	108.7
Industry Sectors*	16.1	50.8	12.5	11.3	46.3	137.0
Transportation Sectors	---	32.9	---	---	2.1	35.0
Total Final Internal Consumption (TFIC)	25.2	135.5	22.3	11.3	81.4	275.7
Electricity Generation	44.8	14.0	7.8	2.0	-68.6	---
Gas Manufacture***	13.3	---	---	-13.3	---	---
Non-Energy Use	---	17.1	---	---	---	17.1
Total Internal Consumption (TIC)	83.3	166.6	30.1	---	12.8	292.8
Bunkers	---	5.7	---	---	---	5.7
Total Requirements	83.3	172.3	30.1	---	12.8	298.5

* Includes Consumption by the Energy Sector and Distribution Losses.
** Includes Input to Derived Gases.
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ENERGY CONSUMPTION PROSPECTS FOR GERMANY

1980

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	5.6	58.8	16.1	0.0	54.1	134.6
Industry Sectors*	14.7	62.9	19.3	9.4	60.2	166.5
Transportation Sectors	---	42.7	---	---	2.2	44.9
Total Final Internal Consumption (TFIC)	20.3	164.4	35.4	9.4	116.5	346.0
Electricity Generation	46.9	23.2	11.2	2.5	-83.8	---
Gas Manufacture***	11.9	---	---	-11.9	---	---
Non-Energy Use	---	21.8	---	---	---	21.8
Total Internal Consumption (TIC)	79.1	209.4	46.6	---	32.7	367.8
Bunkers	---	6.1	---	---	---	6.1
Total Requirements	79.1	215.5	46.6	---	32.7	373.9

1985

Commercial-Residential	3.5	63.7	20.3	0.0	81.2	168.7
Industry Sectors*	14.7	75.5	26.9	7.4	81.8	206.3
Transportation Sectors	---	56.0	---	---	3.0	59.0
Total Final Internal Consumption (TFIC)	18.2	195.2	47.2	7.4	166.0	434.0
Electricity Generation	46.9	35.6	14.5	2.4	-99.4	---
Gas Manufacture***	9.8	---	---	-9.8	---	---
Non-Energy Use	---	29.5	---	---	---	29.5
Total Internal Consumption (TIC)	74.9	260.3	61.7	---	66.6	463.5
Bunkers	---	6.5	---	---	---	6.5
Total Requirements	74.9	266.8	61.7	---	66.6	470.0

* Includes Consumption by the Energy Sector and Distribution Losses.
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ENERGY CONSUMPTION PROSPECTS FOR DENMARK

1972

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	0.2	6.8	---	---	2.9	9.9
Industry Sectors*	0.1	3.3	---	---	1.9	5.3
Transportation Sectors	---	2.9	---	---	0.0	2.9
Total Final Internal Consumption (TFIC)	0.3	13.0	---	---	4.8	18.1
Electricity Generation	1.2	4.2	---	---	-5.4	---
Gas Manufacture***	---	---	---	---	---	---
Non-Energy Use	---	1.1	---	---	---	1.1
Total Internal Consumption (TIC)	1.5	18.3	---	---	-0.6	19.2
Bunkers	---	0.8	---	---	---	0.8
Total Requirements	1.5	19.1	---	---	-0.6	20.0

1975

Commercial-Residential	0.3	8.1	---	---	3.2	11.6
Industry Sectors*	0.1	3.2	---	---	2.1	5.4
Transportation Sectors	---	3.2	---	---	0.0	3.2
Total Final Internal Consumption (TFIC)	0.4	14.5	---	---	5.3	20.2
Electricity Generation	2.5	2.8	---	---	-5.3	---
Gas Manufacture***	---	---	---	---	---	---
Non-Energy Use	---	1.1	---	---	---	1.1
Total Internal Consumption (TIC)	2.9	18.4	---	---	---	21.3
Bunkers	---	0.9	---	---	---	0.9
Total Requirements	2.9	19.3	---	---	---	22.2

* Includes Consumption by the Energy Sector and Distribution Losses.

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ENERGY CONSUMPTION PROSPECTS FOR DENMARK

1980						
10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	0.7	10.7	---	---	4.8	16.2
Industry Sectors*	0.3	3.1	---	---	3.1	6.5
Transportation Sectors	---	3.9	---	---	0.1	4.0
Total Final Internal Consumption (TFIC)	1.0	17.7	---	---	8.0	26.7
Electricity Generation	5.2	2.8	---	---	-8.0	---
Gas Manufacture***	---	---	---	---	---	---
Non-Energy Use	---	1.0	---	---	---	1.0
Total Internal Consumption (TIC)	6.2	21.5	---	---	---	27.7
Bunkers	---	1.1	---	---	---	1.1
Total Requirements	6.2	22.6	---	---	---	28.8

1985						
Commercial-Residential	1.0	11.7	---	---	7.5	20.2
Industry Sectors*	0.4	3.6	---	---	4.8	8.8
Transportation Sectors	---	4.5	---	---	0.2	4.7
Total Final Internal Consumption (TFIC)	1.4	19.8	---	---	12.5	33.7
Electricity Generation	7.5	4.0	---	---	-11.5	---
Gas Manufacture***	---	---	---	---	---	---
Non-Energy Use	---	1.4	---	---	---	1.4
Total Internal Consumption (TIC)	8.9	25.2	---	---	1.0	35.1
Bunkers	---	1.2	---	---	---	1.2
Total Requirements	8.9	26.4	---	---	1.0	36.3

* Includes Consumption by the Energy Sector and Distribution Losses.

** Includes Input to Derived Gases.

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ENERGY CONSUMPTION PROSPECTS FOR THE NETHERLANDS

1972

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	0.5	7.4	11.2	0.0	4.8	28.9
Industry Sectors*	1.2	7.1	8.7	0.5	7.3	24.8
Transportation Sectors	0.0	7.2	---	---	0.2	7.4
Total Final Internal Consumption (TFIC)	1.7	21.7	19.9	0.5	12.3	56.1
Electricity Generation	0.7	2.8	8.8	0.3	-12.6	---
Gas Manufacture***	0.8	---	---	-0.8	---	---
Non-Energy Use	---	2.3	---	---	---	2.3
Total Internal Consumption (TIC)	3.2	26.8	28.7	---	-0.3	58.4
Bunkers	---	12.5	---	---	---	12.5
Total Requirements	3.2	39.3	28.7	---	-0.3	70.9

1975

Commercial-Residential	0.0	7.7	11.2	0.0	4.9	23.8
Industry Sectors*	1.4	11.5	12.2	0.4	7.5	33.0
Transportation Sectors	---	8.4	---	---	0.2	8.6
Total Final Internal Consumption (TFIC)	1.4	27.6	23.4	0.4	12.6	65.4
Electricity Generation	---	3.5	8.1	0.3	-11.9	---
Gas Manufacture***	0.7	---	---	-0.7	---	---
Non-Energy Use	---	3.9	---	---	---	3.9
Total Internal Consumption (TIC)	2.1	35.0	31.5	---	0.7	69.3
Bunkers	---	14.1	---	---	---	14.1
Total Requirements	2.1	49.1	31.5	---	0.7	83.4

* Includes Consumption by the Energy Sector and Distribution Losses.

** Includes Input to Derived Gases.

*** Figures Given Are Input to Derived Gases.

****Figures Given Are Input to Generation in Thermal Equivalent

ENERGY CONSUMPTION PROSPECTS FOR THE NETHERLANDS

1980

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	---	8.4	15.4	0.0	7.3	31.1
Industry Sectors*	1.4	14.7	17.7	0.5	11.3	45.6
Transportation Sectors	---	10.5	---	---	0.2	10.7
Total Final Internal Consumption (TFIC)	1.4	33.6	33.1	0.5	18.8	87.4
Electricity Generation	---	3.6	12.1	0.2	-15.9	---
Gas Manufacture***	0.7	---	---	-0.7	---	---
Non-Energy Use	---	4.9	---	---	---	4.9
Total Internal Consumption (TIC)	2.1	42.1	45.2	--	2.9	92.3
Bunkers	---	14.9	---	---	---	14.9
Total Requirements	2.1	57.0	45.2	---	2.9	107.2

1985

Commercial-Residential	---	9.8	19.6	0.0	10.3	39.7
Industry Sectors*	1.4	17.1	25.4	0.5	16.1	60.5
Transportation Sectors	---	13.3	---	---	0.2	13.5
Total Final Internal Consumption (TFIC)	1.4	40.2	45.0	0.5	26.6	113.7
Electricity Generation	---	5.2	14.5	0.2	-19.9	---
Gas Manufacture***	0.7	---	---	-0.7	---	---
Non-Energy Use	---	6.7	---	---	---	6.7
Total Internal Consumption (TIC)	2.1	52.1	59.5	---	6.7	120.4
Bunkers	---	15.3	---	---	---	15.3
Total Requirements	2.1	67.4	59.5	---	6.7	135.7

* Includes Consumption by the Energy Sector and Distribution Losses.
** Includes Input to Derived Gases.
*** Figures Given Are Input to Derived Gases.
****Figures Given Are Input to Generation in Thermal Equivalent

1972

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	2.5	8.9	1.3	0.0	2.7	15.4
Industry Sectors*	5.1	7.9	3.7	3.2	7.7	27.6
Transportation Sectors	0.0	5.2	---	---	0.2	5.4
Total Final Internal Consumption (TFIC)	7.6	22.0	5.0	3.2	10.6	48.4
Electricity Generation	1.8	5.3	1.7	1.1	-9.9	---
Gas Manufacture***	4.3	---	---	-4.3	---	---
Non-Energy Use	---	2.6	---	---	---	2.6
Total Internal Consumption (TIC)	13.7	29.9	6.7	---	0.7	51.0
Bunkers	---	3.2	---	---	---	3.2
Total Requirements	13.7	33.1	6.7	---	0.7	54.2

1975

Commercial-Residential	2.1	8.8	2.2	0.0	3.7	16.8
Industry Sectors*	5.1	11.6	4.3	3.8	8.3	33.1
Transportation Sectors	---	5.8	---	---	0.1	5.9
Total Final Internal Consumption (TFIC)	7.2	26.2	6.5	3.8	12.1	55.8
Electricity Generation	2.1	4.8	2.1	1.0	-10.0	---
Gas Manufacture***	4.8	---	---	-4.8	---	---
Non-Energy Use	---	3.9	---	---	---	3.9
Total Internal Consumption (TIC)	14.1	34.9	8.6	---	2.1	59.7
Bunkers	---	3.7	---	---	---	3.7
Total Requirements	14.1	38.6	8.6	---	2.1	63.4

* Includes Consumption by the Energy Sector and Distribution Losses.
** Includes Input to Derived Gases.
*** Figures Given Are Input to Derived Gases.
****Figures Given Are Input to Generation in Thermal Equivalent

ENERGY CONSUMPTION PROSPECTS FOR BELGIUM-LUXEMBOURG

1980

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	0.7	11.7	3.6	0.0	5.4	21.4
Industry Sectors*	3.9	15.7	7.3	3.1	11.7	41.7
Transportation Sectors	---	7.2	---	---	0.1	7.3
Total Final Internal Consumption (TFIC)	4.6	34.6	10.9	3.1	16.3	70.4
Electricity Generation	2.1	6.5	2.5	0.6	-11.7	---
Gas Manufacture***	3.7	---	---	-3.7	---	---
Non-Energy Use	---	5.3	---	---	---	5.3
Total Internal Consumption (TIC)	10.4	46.4	13.4	---	5.5	75.7
Bunkers	---	4.1	---	---	---	4.1
Total Requirements	10.4	50.5	13.4	---	5.5	79.8

1985

	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	---	13.9	5.0	0.0	7.1	26.0
Industry Sectors*	3.5	18.4	9.3	3.2	16.0	50.4
Transportation Sectors	---	9.4	---	---	0.1	9.5
Total Final Internal Consumption (TFIC)	3.5	41.7	14.3	3.2	23.2	85.9
Electricity Generation	2.1	7.8	2.6	0.4	-12.9	---
Gas Manufacture***	3.6	---	---	-3.6	---	---
Non-Energy Use	---	7.2	---	---	---	7.2
Total Internal Consumption (TIC)	9.2	56.7	16.9	---	10.3	93.1
Bunkers	---	4.6	---	---	---	4.6
Total Requirements	9.2	61.3	16.9	---	10.3	97.7

* Includes Consumption by the Energy Sector and Distribution Losses.

** Includes Input to Derived Gases.

*** Figures Given Are Input to Derived Gases.

****Figures Given Are Input to Generation in Thermal Equivalent

ENERGY CONSUMPTION PROSPECTS FOR ITALY

1972

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	0.7	24.6	3.7	0.0	8.1	37.1
Industry Sectors*	3.3	27.9	9.3	2.6	19.5	62.6
Transportation Sectors	0.2	18.9	---	---	---	19.8
Total Final Internal Consumption (TFIC)	4.2	71.4	13.0	2.6	28.3	119.5
Electricity Generation	1.0	15.5	1.0	0.5	-18.0	---
Gas Manufacture***	3.1	---	---	-3.1	---	---
Non-Energy Use	---	9.2	---	---	---	9.2
Total Internal Consumption (TIC)	8.3	96.1	14.0	---	10.3	128.7
Bunkers	---	8.6	---	---	---	8.6
Total Requirements	8.3	104.7	14.0	---	10.3	137.3

1975

Commercial-Residential	0.7	25.2	4.9	0.0	11.2	42.0
Industry Sectors*	4.9	35.1	11.2	2.8	27.4	81.4
Transportation Sectors	---	21.0	---	---	0.7	21.7
Total Final Internal Consumption (TFIC)	5.6	81.3	16.1	2.8	39.3	145.1
Electricity Generation	2.1	21.7	1.4	0.7	-25.9	---
Gas Manufacture***	3.5	---	---	-3.5	---	---
Non-Energy Use	---	11.8	---	---	---	11.8
Total Internal Consumption (TIC)	11.2	114.8	17.5	---	13.4	156.9
Bunkers	---	9.2	---	---	---	9.2
Total Requirements	11.2	124.0	17.5	---	13.4	166.1

* Includes Consumption by the Energy Sector and Distribution Losses.
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ENERGY CONSUMPTION PROSPECTS FOR ITALY

1980

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	0.0	32.9	8.4	0.0	17.4	58.7
Industry Sectors*	4.9	45.8	16.8	2.6	41.3	111.4
Transportation Sectors	---	25.2	---	---	0.7	25.9
Total Final Internal Consumption (TFIC)	4.9	103.9	25.2	2.6	59.4	196.0
Electricity Generation	2.8	34.0	1.3	0.9	-39.0	---
Gas Manufacture***	3.5	---	---	-3.5	---	---
Non-Energy Use	---	15.8	---	---	---	15.8
Total Internal Consumption (TIC)	11.2	153.7	26.5	---	20.4	211.8
Bunkers	---	10.7	---	---	---	10.7
Total Requirements	11.2	164.4	26.5	---	20.4	222.5

1985

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	0.0	42.0	11.9	0.0	25.0	78.9
Industry Sectors*	4.9	58.4	21.8	2.7	59.3	147.1
Transportation Sectors	---	33.6	---	---	1.1	34.7
Total Final Internal Consumption (TFIC)	4.9	134.0	33.7	2.7	85.4	260.7
Electricity Generation	2.8	46.4	1.4	0.8	-51.4	---
Gas Manufacture***	3.5	---	---	-3.5	---	---
Non-Energy Use	---	22.8	---	---	---	22.8
Total Internal Consumption (TIC)	11.2	203.2	35.1	---	34.0	283.5
Bunkers	---	11.8	---	---	---	11.8
Total Requirements	11.2	215.0	35.1	---	34.0	295.3

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ENERGY CONSUMPTION PROSPECTS FOR FRANCE

1972

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	5.7	35.6	5.1	0.0	11.5	57.9
Industry Sectors*	9.2	34.5	5.7	4.1	25.4	78.9
Transportation Sectors	0.1	25.0	---	---	1.3	26.4
Total Final Internal Consumption (TFIC)	15.0	95.1	10.8	4.1	38.2	163.2
Electricity Generation	8.9	12.4	2.0	1.4	-24.7	---
Gas Manufacture***	5.5	---	---	-5.5	---	---
Non-Energy Use	---	11.4	---	---	---	11.4
Total Internal Consumption (TIC)	29.4	118.9	12.8	---	13.5	174.6
Bunkers	---	5.3	---	---	---	5.3
Total Requirements	29.4	124.2	12.8	---	13.5	179.9

1975

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	3.5	34.3	7.7	0.0	14.1	59.6
Industry Sectors*	9.1	40.9	8.4	4.9	28.1	91.4
Transportation Sectors	---	24.5	---	---	1.3	25.8
Total Final Internal Consumption (TFIC)	12.6	99.7	16.1	4.9	43.5	176.8
Electricity Generation	5.6	18.9	2.1	1.4	-28.0	---
Gas Manufacture***	6.3	---	---	-6.3	---	---
Non-Energy Use	---	13.7	---	---	---	13.7
Total Internal Consumption (TIC)	24.5	132.3	18.2	---	15.5	190.5
Bunkers	---	5.5	---	---	---	5.5
Total Requirements	24.5	137.8	18.2	---	15.5	196.0

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ENERGY CONSUMPTION PROSPECTS FOR FRANCE

1980

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	2.8	40.6	9.1	0.0	21.6	74.1
Industry Sectors*	9.1	54.5	15.6	4.7	40.4	124.3
Transportation Sectors	---	31.5	---	---	1.5	33.0
Total Final Internal Consumption (TFIC)	11.9	126.6	24.7	4.7	63.5	231.4
Electricity Generation	6.3	26.2	2.7	1.6	-36.8	---
Gas Manufacture***	6.3	---	---	-6.3	---	---
Non-Energy Use	---	19.0	---	---	---	19.0
Total Internal Consumption (TIC)	24.5	171.8	27.4	---	26.7	250.4
Bunkers	---	5.8	---	---	---	5.8
Total Requirements	24.5	177.6	27.4	---	26.7	256.2

1985

Commercial-Residential	1.4	47.6	11.9	0.0	33.2	94.1
Industry Sectors*	7.0	71.5	21.0	4.2	58.2	161.9
Transportation Sectors	---	41.3	---	---	1.5	42.8
Total Final Internal Consumption (TFIC)	8.4	160.4	32.9	4.2	92.9	298.8
Electricity Generation	6.3	34.9	3.8	1.4	-46.4	---
Gas Manufacture***	5.6	---	---	-5.6	---	---
Non-Energy Use	---	27.9	---	---	---	27.9
Total Internal Consumption (TIC)	20.3	223.2	36.7	---	46.5	326.7
Bunkers	---	6.5	---	---	---	6.5
Total Requirements	20.3	229.7	36.7	---	46.5	333.2

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ENERGY CONSUMPTION PROSPECTS FOR THE U.K./IRELAND

1972

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	16.8	13.9	13.9	0.0	39.7	84.3
Industry Sectors*	14.4	42.0	10.2	6.2	112.2	112.2
Transportation Sectors	0.1	31.2			0.8	32.1
Total Final Internal Consumption (TFIC)	31.3	87.1	24.1	6.2	79.9	228.6
Electricity Generation	45.5	21.8	1.8	0.4	-69.5	
Gas Manufacture***	6.6			-6.6		
Non-Energy Use		14.0				14.0
Total Internal Consumption (TIC)	83.4	122.9	25.9		10.4	242.6
Bunkers		5.7				5.7
Total Requirements	83.4	128.6	25.9		10.4	248.3

1975

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	12.4	29.3	18.0	0.0	44.7	104.4
Industry Sectors*	13.0	36.4	14.0	2.4	45.7	111.5
Transportation Sectors		50.2			1.1	51.2
Total Final Internal Consumption (TFIC)	25.4	115.9	31.9	2.4	91.5	267.1
Electricity Generation	42.8	29.7	5.7	1.0	-79.2	
Gas Manufacture***	3.4			-3.4		
Non-Energy Use		12.3				12.3
Total Internal Consumption (TIC)	71.6	157.9	37.6		12.3	279.4
Bunkers		5.6				5.6
Total Requirements	71.6	163.5	37.6		12.3	285.0

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ENERGY CONSUMPTION PROSPECTS FOR THE U.K./IRELAND

1980

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	7.0	34.1	22.3	0.0	51.6	115.0
Industry Sectors*	10.5	56.8	16.4	3.7	55.8	143.2
Transportation Sectors		61.6			1.1	62.7
Total Final Internal Consumption (TFIC)	17.5	152.5	38.7	3.7	108.5	320.9
Electricity Generation	24.4	47.0	9.4	1.0	-81.8	
Gas Manufacture***	4.7			-4.7		
Non-Energy Use		19.7				19.7
Total Internal Consumption (TIC)	46.6	219.2	48.1		26.7	340.6
Bunkers		9.2				9.2
Total Requirements	46.6	228.4	48.1		26.7	349.8

1985

10^{13} KCAL (MTOE)	Solids	Oil**	Natural Gas	Mnfc. Gas***	Elec. ****	Total
Commercial-Residential	4.6	41.0	27.9	0.0	63.0	136.5
Industry Sectors*	11.5	62.1	18.8	3.7	69.4	165.5
Transportation Sectors		78.6			0.9	79.5
Total Final Internal Consumption (TFIC)	16.1	181.7	46.7	3.7	133.3	381.5
Electricity Generation	18.4	58.1	10.1	1.1	-87.7	
Gas Manufacture***	4.8			-4.8		
Non-Energy Use		24.2				24.2
Total Internal Consumption (TIC)	39.3	264.0	56.8		45.6	405.7
Bunkers		10.8				10.8
Total Requirements	39.3	274.8	56.8		45.6	416.5

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